



INDUSTRIAL COMMISSION OF NORTH DAKOTA

Kelly Armstrong
Governor

Drew H. Wrigley
Attorney General

Doug Goehring
Agriculture Commissioner

Tuesday, August 25, 2026

Governor's Conference Room or Microsoft Teams – 8:00 am

[Join the meeting now](#)

Join on your computer or mobile app

Or call in (audio only)

[+1 701-328-0950,,865898601#](#)

I. Roll Call and Pledge of Allegiance

(approximately 8:00 am)

II. North Dakota Mill and Elevator – Cathy Dub

- A. **Consideration of Approval of FY 2027 Capital Plan** (Attachment 1)
- B. Other ND Mill Business

(approximately 8:15 am)

III. North Dakota Transmission Authority – Claire Vigesaa

- A. Presentation of Annual Report and Report on Resiliency of the Electric Grid in North Dakota (Attachment 2)
- B. Other NDTA Business

(approximately 8:30 am)

IV. North Dakota Pipeline Authority – Justin Kringstad

- A. Pipeline Authority Industry Update (Attachment 3)
- B. Other Pipeline Authority Business

(approximately 8:50 am)

V. Department of Mineral Resources – Nathan Anderson, Mark Bohrer

- A. Director's Update (Attachment 5)
- B. Other DMR Business

(approximately 9:00 am)

VI. North Dakota Public Finance Authority – DeAnn Ament

A. Consideration of Approval of the following State Revolving Fund

Loans:

- i.** City of Casselton – Clean Water - \$6,221,000 (Attachment 6)
- ii.** City of Fessenden – Clean Water \$2,100,000 (Attachment 7)
- iii.** City of Grant Forks – Drinking Water - \$2,042,000 (Attachment 8)

B. Presentation of memo of State Revolving Fund Loans approved by PFA Advisory Committee Pursuant to Policy P-3B (Attachment 9)

- i.** City of Bowman – Drinking Water \$1,193,000 (Attachment 9A)
- ii.** City of Casselton – Drinking Water - \$1,624,000 (Attachment 9B)
- iii.** City of Stanley – Drinking Water - \$300,000 (Attachment 9C)
- iv.** City of Stanley – Clean Water - \$350,000 (Attachment 9D)

C. Other NDPFA Business

**Meeting Closed to the Public for Executive Session
Pursuant to NDCC 44-04-18.4, 44-04-19.1, 44-04-19.2 and
54-63.1-06**

(approximately 9:15 am)

VII. Litigation Consultation – Phil Axt

- A.** MN Carbon Free Legislation
- B.** Pore Space Litigation

(approximately 9:35 am)

VIII. Clean Sustainable Energy Authority – Jordan Kannianen, Kelvin Hullet

- A. Consideration of Approval of Confidentiality Request** (Confidential Attachment 10)

Meeting Returns to Public Session

IX. Action on Executive Session Topics

(approximately 9:45 am)

X. Clean Sustainable Energy Authority – Jordan Kannianen, Kelvin Hullet

- A. Project Presentation – Minnkota Power Cooperative, Inc. (DCC East, LLC) and Reliant Carbon Capture and Storage, LLC (Reliant Tundra Capture, LLC) (Attachment 10)
- B. Other CSEA Business

**Meeting Closed to the Public for Executive Session
Pursuant to NDCC 6-09-35, 44-04-18.4, 44-04-19.1, 44-04-19.2 and
54-63.1-06**

(approximately 10:00 am)

XI. Clean Sustainable Energy Authority – Jordan Kannianen, Kelvin Hullet

- A. **Consideration of Recommendation by Clean Sustainable Energy Authority for Approval of Two Loans** (Confidential Attachment 11)
- B. Other CSEA Confidential Business

(approximately 10:15 am)

XII. Bank of North Dakota Executive Session – Don Morgan, Rick Geloff, Attorneys James Steven and Carlin McCoy of Troutman Pepper Locke Law Firm via Teams.

- A. Attorney Consultation Regarding Fiserv Contract Negotiations (Confidential Attachment 12)
- B. Other BND Confidential Business

Meeting Returns to Public Session

(approximately 10:45 am)

XIII. Action on Executive Session Topics

(approximately 10:55 am)

XIV. Industrial Commission Administrative Office – Karen Tyler

- A. **Consideration of Approval of July 23, 2026, Industrial Commission Meeting Minutes** (Attachment 13)
- B. Other Administrative Office Business

XV. Adjournment

Next Regular Industrial Commission Meeting – Tuesday, September 22, 2026
9:00 am – 12:30 pm
Governor's Conference Room

NORTH DAKOTA MILL
Capital Expenditures for FY 2026
August 25, 2026

Year	Capital Expense Item	Total Budget	FY 2026 Remaining Budget	FY 2026 Net Capital Cost	Under / (Over)	Completed Project Cost
2022	Grain Terminal Belt Conveyor Upgrades	460,000	457,514		460,000	-
* 2023	Midds Storage and Handling System Phase I, II, & III	56,000,000	4,596,037	3,709,359	886,678	
2023	K Mill High Pressure Fans	450,000	268,650	171,662	96,988	353,012
2023	Packing Flour Transfer Upgrade	375,000	121,098	-	121,098	253,902
2023	Flour Transfer B Filter and Conveyor	310,000	63,706	-	63,706	246,294
2023	Fire Protection Water Pump	225,000	33,519	20,791	12,729	212,271
* 2023	Electrical Generation	3,500,000	2,177,455	94,551	2,082,904	
2024	B Mill Reflow	700,000	235,497	224,472	11,025	688,975
2024	K Mill Upgrades	650,000	88,353	74,502	13,851	636,149
* 2024	E Mill Upgrades	450,000	197,268	128,622	68,647	
2024	Regrind System Capacity Increase	450,000	258,817	217,414	41,402	408,598
2024	A, B, C Mill Combustioners	450,000	25,000	-	25,000	425,000
2024	B & K Mill Tempering Systems	300,000	20,237	-	20,237	279,763
* 2024	WW Mill Upgrades	250,000	203,069	103,348	99,721	
2024	Lab & K Mill HVAC Upgrades	250,000	97,610	-	97,610	152,390
2024	G Mill Farina System	75,000	75,000	68,462	6,538	68,462
2024	Loadout Software	500,000	293,886	-	293,886	206,114
* 2025	Terminal Leg Head and Boot Replacements Engineering	550,000	546,577	260,274	286,303	
* 2025	B-Mill Improvements	1,700,000	1,336,733	783,828	552,905	
2025	K-Mill Tanks & Splitters	110,000	91,541	79,382	12,160	97,840
2025	H-Mill & Cleaning House Upgrades	220,000	220,000	214,549	5,451	214,549
* 2025	D-Mill Bucket Elevator & Cleaning House	350,000	350,000	-	350,000	
2025	G & I Mill Impactors	140,000	39,234	39,060	174	139,826
* 2025	Tote Packers (2)	350,000	298,578	79,268	219,311	
2025	C Mill Rollstand Controllers	250,000	250,000	153,206	96,794	153,206
* 2025	Rotex Screeners	200,000	200,000	-	200,000	
2025	A/B Mill 9th Floor Project Engineering	250,000	244,460	211,224	33,236	216,764
* 2025	Track 3 Flour Loadout Engineering	250,000	250,000	100,857	149,143	
2025	Roof Replacements	1,050,000	1,038,454	691,838	346,616	703,384
2025	Road & Lot Upgrades	350,000	161,149	78,168	82,981	267,019
2025	Rail Track Upgrades	1,250,000	1,249,651	995,943	253,708	996,292
2025	Lockers & Bathrooms Upgrade	150,000	150,000	142,800	7,200	142,800
2025	Air Compressors (3)	150,000	51,859	50,496	1,363	148,637
* 2025	Spare Transformers (2)	250,000	238,266	-	238,266	
* 2025	Switchgear Replacements	450,000	450,000	8,600	441,400	
* 2025	Roll Chill/Corrugation Equipment	800,000	330,331	209,106	121,226	
* 2026	Plant Network Replacement	700,000	700,000	-	700,000	
* 2026	Condinsate Return Tank	200,000	200,000	-	200,000	
* 2026	Pallet Stretch Wrap Machine	200,000	200,000	54,209	145,791	
* 2026	Whole Wheat Optical Sorter	425,000	425,000	324,384	100,616	
2026	Truck and Trailer Parking Lot	150,000	150,000	148,759	1,241	148,759
* 2026	K-Mill Electrical Feeders	600,000	600,000	9,083	590,918	
* 2026	Electracial Capacitors	250,000	250,000	53,335	196,665	
* 2026	C-Mill Entoleters	125,000	125,000	91,465	33,535	
* 2026	Rail Yard Storage Tracks	1,700,000	1,700,000	516,277	1,183,723	
2026	Lab Insulating and Re-Siding	160,000	160,000	140,116	19,884	140,116
2026	Main Office HVAC System	850,000	850,000	-	850,000	-
* 2026	A/B Mill Building 9th Floor Addition	8,500,000	8,500,000	1,454,035	7,045,965	
* 2026	E Mill Expansion Phase I - Equipment	11,500,000	11,500,000	2,414,830	9,085,170	
* 2026	C Mill Wheat Delivery System	700,000	700,000	277,252	422,748	
* 2026	Terminal Bucket Elevator Leg Replacement Phase I	7,900,000	7,900,000	466,046	7,433,954	
	Computers/Technology	300,000	300,000	-	300,000	
2026	Systems Improvements, Replacements, and Upgrades					
	Other	500,000	500,000	167,003	332,997	
2026	2022 GMC Sierra 1500 Denali					46,408
2026	Protein Analyzer FP 828					54,589
2026	Flour Blending Bulk Plant Conveyor					51,971
2026	Cleaning House Electrical					14,035
Total Capital Expenditures		\$ 108,975,000	\$ 51,469,548	\$ 15,028,572	\$ 36,443,462	\$ 7,467,126

* Carried over to Fiscal Year 2027

NORTH DAKOTA MILL
Capital Plan for FY 2027
August 25, 2026

Capital Expense Item	
Carryover from FY 2026	Remaining Budget
Plant	
Midds Storage and Handling System Phase I, II, & III	886,678
Electrical Generation	2,082,904
E Mill Upgrades	68,647
WW Mill Upgrades	99,721
Terminal Leg Head and Boot Replacements Engineering	286,303
B-Mill Improvements	552,905
D-Mill Bucket Elevator & Cleaning House	350,000
Tote Packers (2)	219,311
Rotex Screeners	200,000
Track 3 Flour Loadout Engineering	149,143
Spare Transformers (2)	238,266
Switchgear Replacements	441,400
Roll Chill/Corrugation Equipment	121,226
Plant Network Replacement	700,000
Condinsate Return Tank	200,000
Pallet Stretch Wrap Machine	145,791
Whole Wheat Optical Sorter	100,616
K-Mill Electrical Feeders	590,918
Electrical Capacitors	196,665
C-Mill Entolers	33,535
Rail Yard Storage Tracks	1,183,723
A/B Mill Building 9th Floor Addition	7,045,965
E Mill Expansion Phase I - Equipment	9,085,170
C Mill Wheat Delivery System	422,748
Terminal Bucket Elevator Leg Replacement Phase I	7,433,954
Total Carryover Capital Expenditures	\$ 32,835,588
FY 2027 Capital Expense Item	Plan
Plant	
E Mill Expansion Phase II - Equipment Installation	8,500,000
Cleaning House Scourer and Aspirator Replacement (7)	1,200,000
Midds Facility Man Lift	350,000
Main Line Crossover Track	300,000
Paving and Stairs - Old Warehouse Loading Area	200,000
Lab Equipment	300,000
Grain Probes - (2)	300,000
Computers/Technology	
Systems Improvements, replacements, and upgrades	300,000
Other	500,000
Total New Capital Expenditures	\$ 11,950,000
Total Capital Expenditures	\$ 44,785,588

FY 2027 Capital Projects for Consideration

8/25/2026

1	E-Mill Expansion Phase II- Equipment Installation	\$8,500,000
	Installation of process equipment supporting the E-Mill expansion, including wheat cleaning, milling, and material handling/conveying systems. All electrical installation, wiring, and controls integration associated with this equipment will be performed as part of Phase III.	
2	Cleaning House Scourer and Aspirator Replacement (7)	\$1,200,000
	Remove existing worn and outdated grain cleaning equipment and install modern high-capacity grain scourers. The new system will improve grain cleaning efficiency by removing foreign materials, while the integrated aspiration system captures and removes dust, chaff, and other lightweight impurities to enhance product quality and operational performance.	
3	Midds Facility Man Lift	\$350,000
	Purchase and installation of a man-lift within the stairwell of the new Midds Facility to improve personnel access between levels. The lift will enhance operational efficiency, reduce transit time, and provide safer movement throughout the facility.	
4	Main Line Crossover Track	\$300,000
	Construction of a crossover track connecting the two existing main railroad lines at a midpoint location within the facility rail network. The project will improve rail operating efficiency by allowing railcars to be switched between tracks more quickly and safely, particularly when segregating specific car types for loading, unloading, storage, or outbound shipment. This infrastructure improvement will reduce switching complexity, minimize railcar handling time, and enhance overall yard fluidity.	
5	Paving and Stairs - Old Warehouse Loading Area	\$200,000
	Remove and replace deteriorated concrete stairs serving the old warehouse, along with the adjacent pavement. The project will restore safe access, improve site appearance, and address structural and surface deterioration caused by age and wear.	
6	Lab Equipment	\$300,000
	Purchase and installation of laboratory testing equipment to enhance quality assurance for incoming grain and finished flour products. The project includes a Farinograph for evaluating dough development time, water absorption, and flour stability; a FOSS analyzer for rapid measurement of protein, moisture, and ash content in both grain and flour; and a Perten Falling Number system with grinder for assessing sprout damage and enzyme activity in wheat. These testing capabilities will improve product consistency, support quality control programs, and ensure compliance with customer and industry specifications.	
7	Grain Probes (2)	\$300,000
	Remove and replace outdated and worn grain truck probe equipment in the Grain Probe Shack with a modernized sampling and testing system. The upgrade will improve the accuracy and efficiency of grain sampling, enhance reliability, and support efficient grain receiving operations.	
8	Computers / Technology	\$300,000
	Several system improvements, replacements and upgrades are required on our management information system.	
9	Other Capital	\$500,000
Total New Capital Projects		\$ 11,950,000

North Dakota Industrial Commission

**Claire Vigesaa – Executive Director
ND Transmission Authority
August 25, 2026**

TOPICS

- ❑ NDTA Annual Report

 - Activity Highlights

 - Project Highlights

 - Challenges – Linear Infrastructure

 - Transmission Expansion Plans

- ❑ NDTA Resiliency of the Electrical Grid in North Dakota

 - Grid Reliability

- ❑ IIJA Grant Review

ACTIVITY HIGHLIGHTS

- ❑ Advanced Nuclear Energy Interim Committee
- ❑ Hosted the Midwest Governor's Association/Organization of MISO States Transmission Summit
- ❑ Presented on North Dakota's Transmission Authority and Energy Activity
 - National Association of State Energy Offices – D.C.
 - National Electric Reliability Corporation – NERC Workshop – D.C.
 - Grid Works
 - NARUC
 - National Governor's Association Transmission Summit

ACTIVITY HIGHLIGHTS-ENGAGEMENT

ND PSC

Midwest Independent System Operator (MISO)

Quarterly Meetings with the Department of Commerce

County Commission Meetings

North Dakota Pipeline Authority

North Dakota Petroleum Council

Energy Development and Transmission Interim Committee

DOE Infomercial on GRIP Program

Governor's Office

Southwest Power Pool (SPP)

Planning & Zoning Meetings

Western Dakota Energy Association

North Dakota Lignite Council

Energy Hawks

Bison to Bakken

Trade Associations

North Dakota Transmission Owner & Developer Visits

PROJECT HIGHLIGHTS

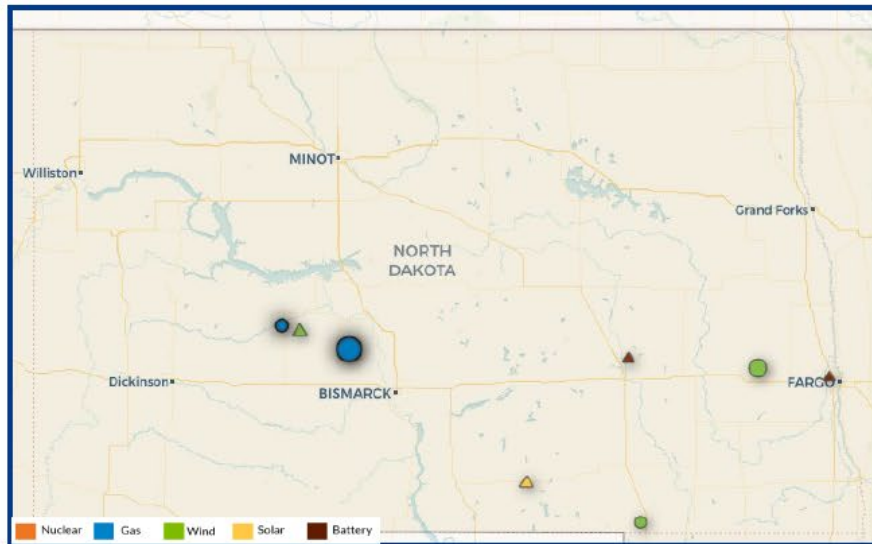
- ❑ North Plains Connector – 525 kV HVDC Interregional Project Moves Forward
- ❑ MISO's "Futures" Process eyes North Dakota for Generation

MISO FUTURES SLIDE (COMPLIMENTS OF OTTER TAIL POWER COMPANY)

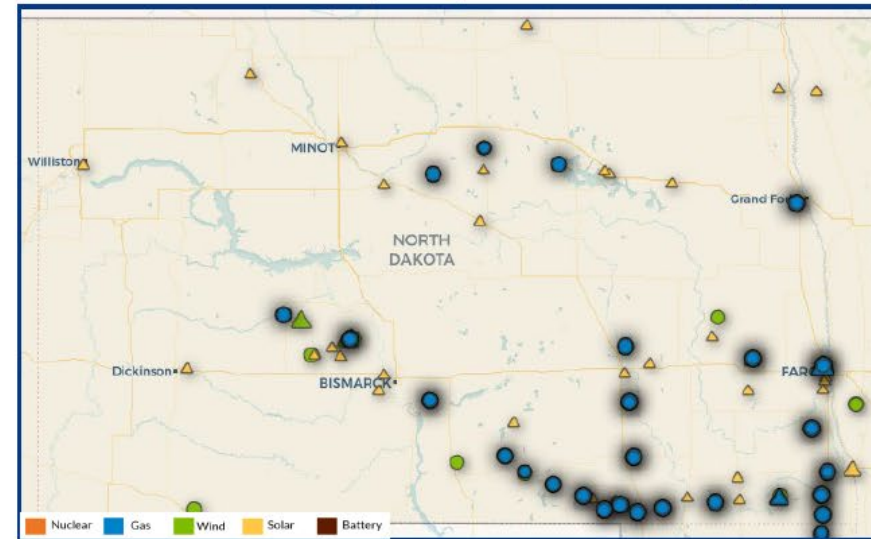
YOUR ADVOCACY IS CREATING CHANGE

Energy infrastructure, including WBI's Bakken East Pipeline, means local jobs, tax revenue, and economic development.

Future 3 – ND Preliminary Generation Siting



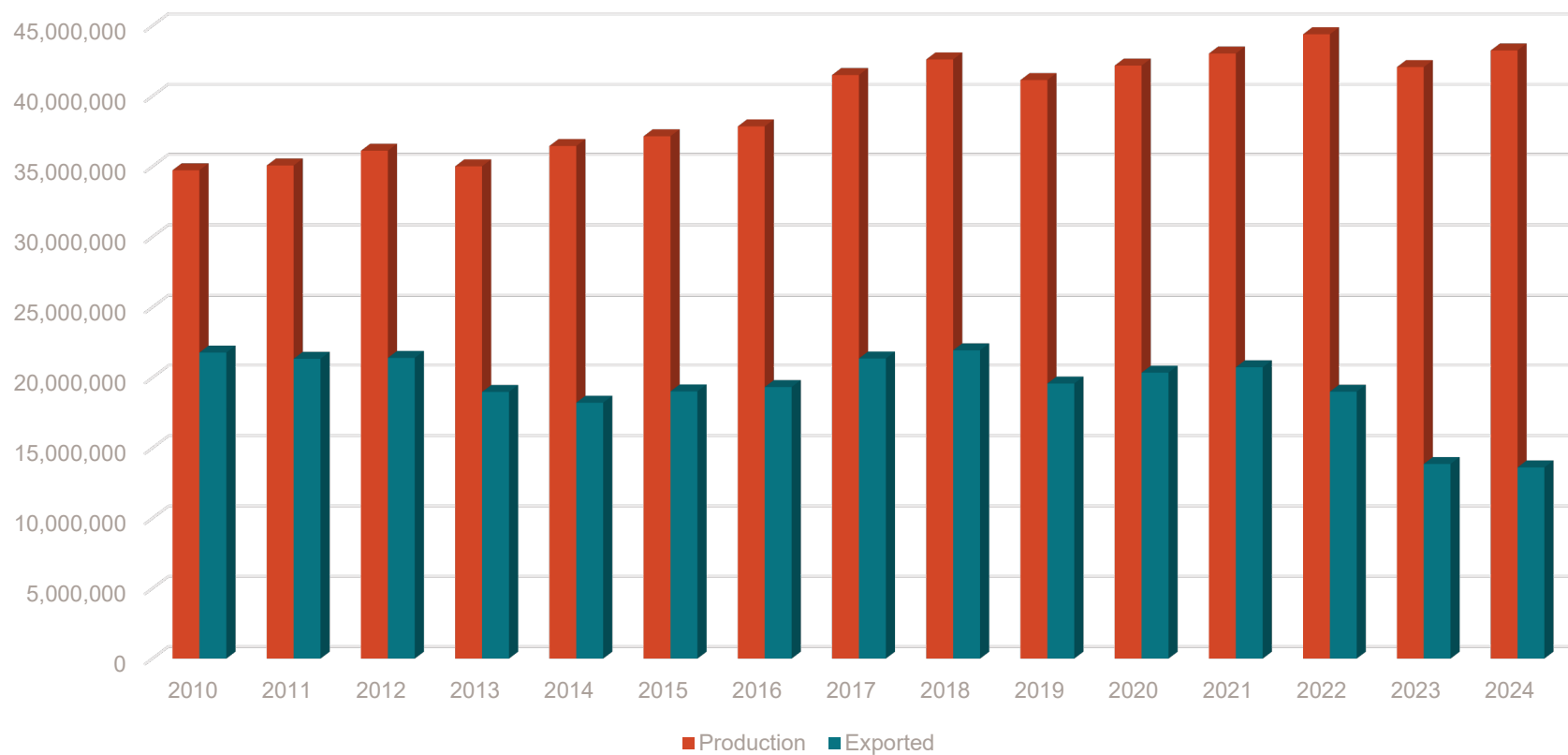
Future 3 – ND Final Generation Siting



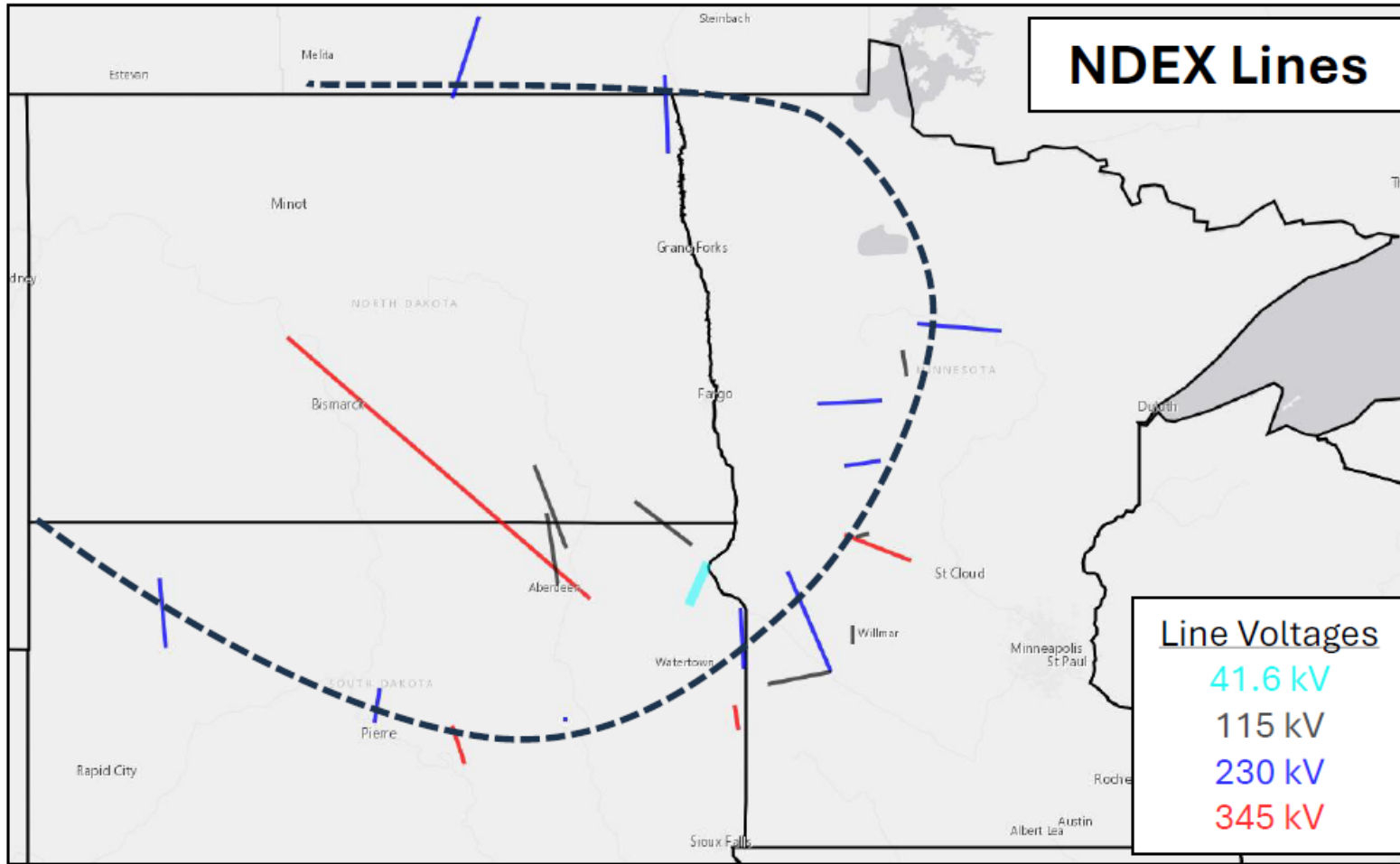
5.02 GW → 19.04 GW | Advocacy drove a nearly 4x increase in North Dakota generation siting

6

Electricity (MWHrs) Produced in ND vs Exported-(EIA.GOV)



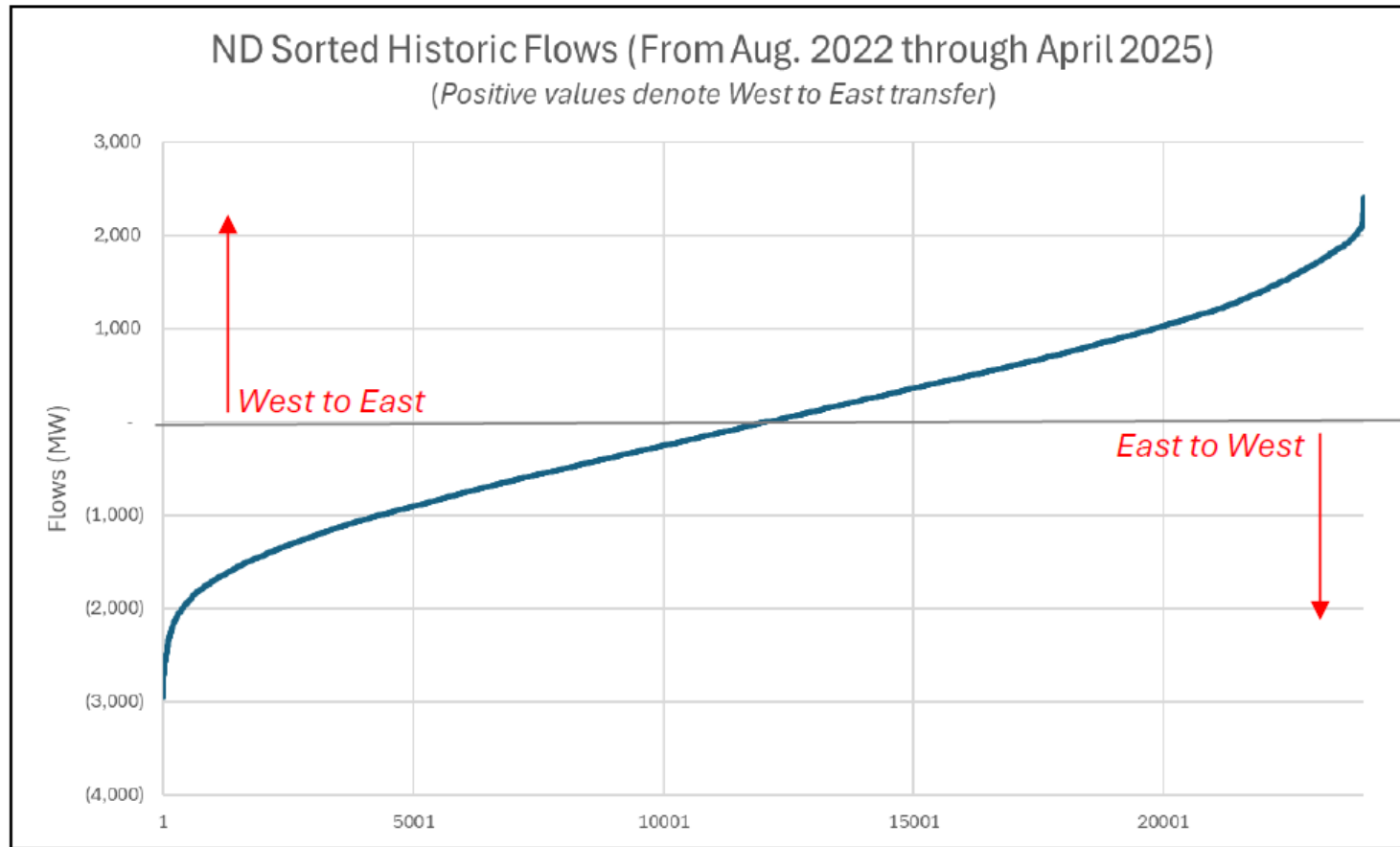
NDEX – NORTH DAKOTA EXPORT



Defining NDEX

- NDEX (or North Dakota Export) interface is a historic reliability constraint and it is a summation of power flows on several transmission lines and this NDEX data flow is still tracked by MISO
- NDEX flow directionality is historically impacted by generation and load levels in ND and surrounding states/provinces

NDEX HISTORIC FLOWS (SINCE AUGUST 2022)



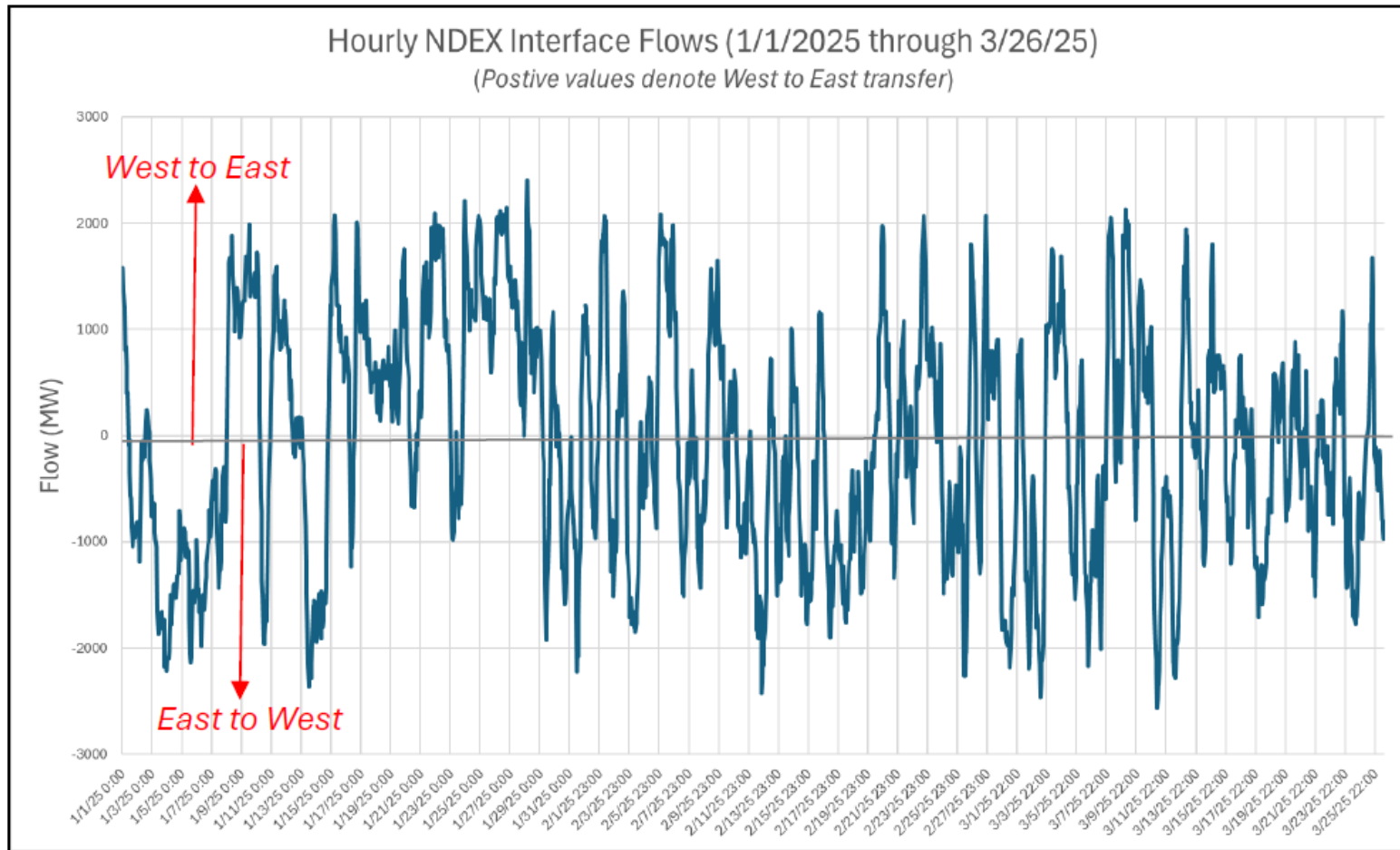
While the day-to-day flows on NDEX change directions, over the past almost three years **flows have gone either direction an equal number of hours.**

Total Hours:

Flows to ND: 12,079

Flows to MN: 11,899

NDEX HISTORIC FLOWS (Q1 2025)



NDEX flows frequently shift – as often as hourly and not less than daily – between west to east and east to west transfer.

LINEAR INFRASTRUCTURE CHALLENGES

- ☐ Increasing Costs of Materials
- ☐ Siting, increasingly difficult
- ☐ Live in an age of abundant information...some of it accurate
- ☐ Societal confusion regarding due process
- ☐ Huge projects, multi-generational impact
- ☐ Limited training and tools for decision makers

MASSIVE LOAD GROWTH OPPORTUNITIES

Data Center Load Growth Projections

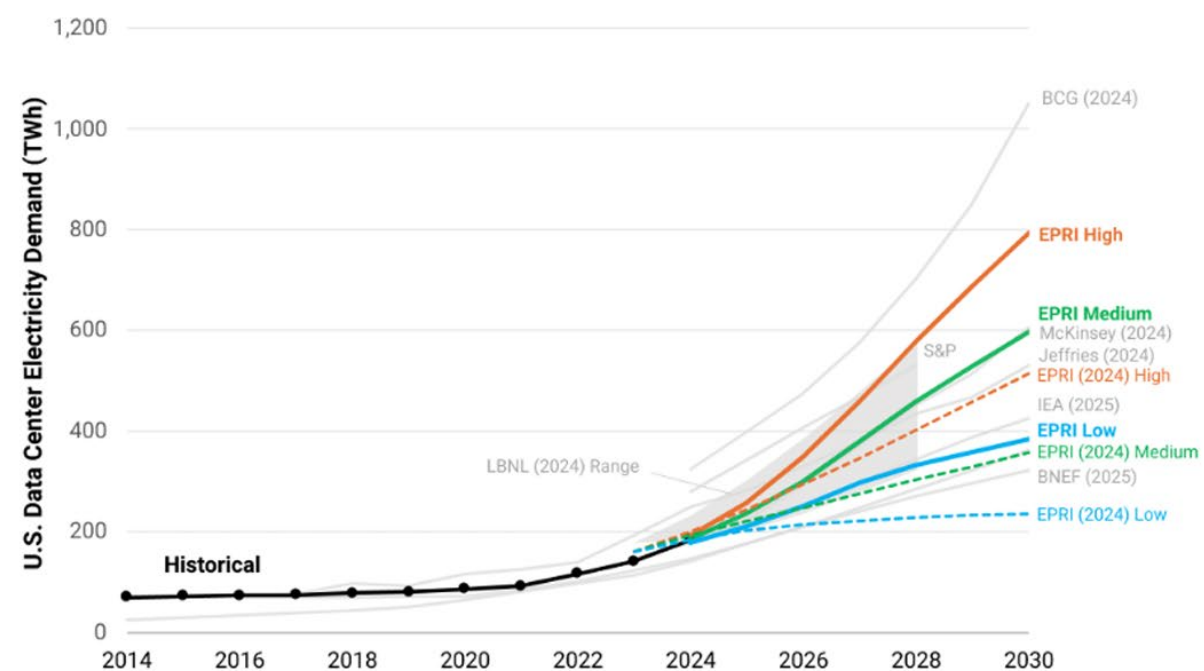


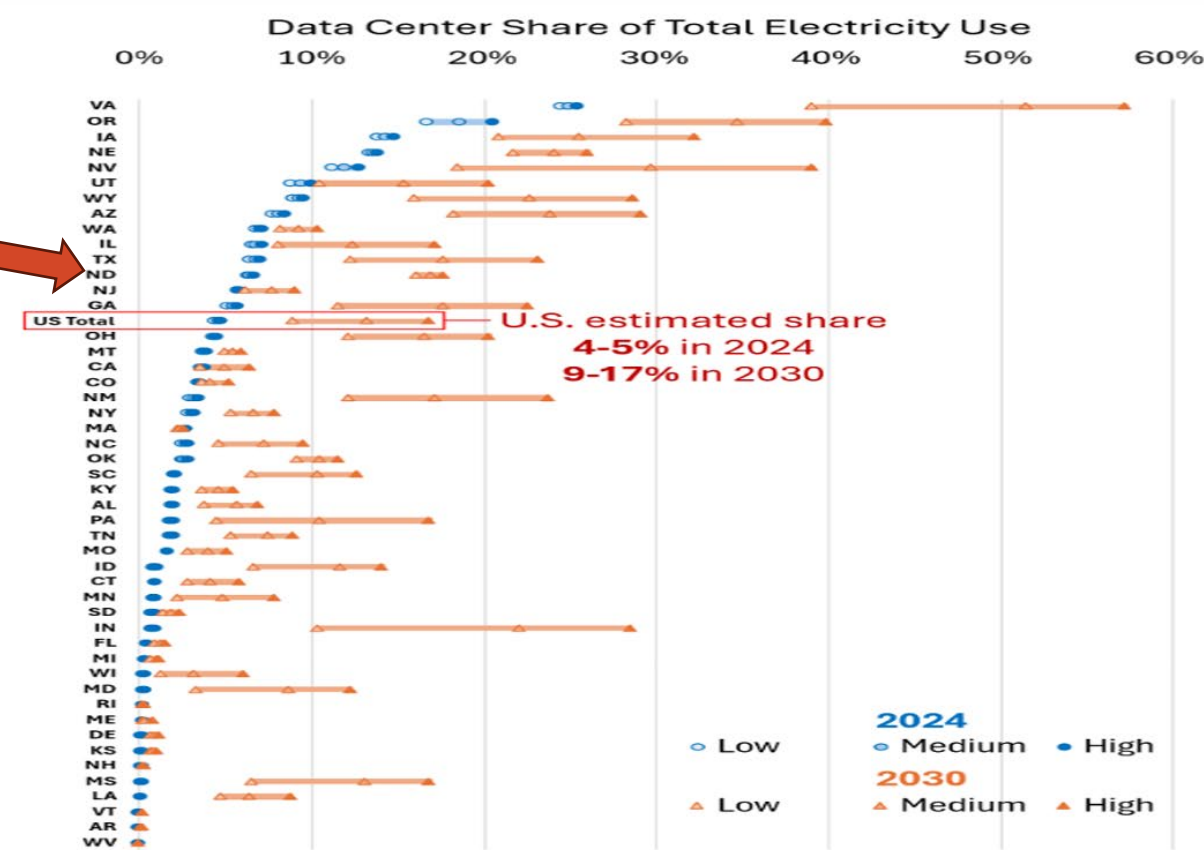
Figure ES-2. Comparison of U.S. data center annual electricity consumption projections. Projections in this study span a similar range to the LBNL (2024) report. Shaded band shows scenarios from LBNL (2024); lines show recent external estimates, including BCG (2024), BloombergNEF (2025), EPRI (2024a), IEA (2025), Jefferies (2024), McKinsey (2024), S&P (2024). EPRI estimates include small- and large-scale data centers as well as cryptocurrency mining.

Source: <https://powering-intelligence.epri.com/executive-summary.html>

PERCENTAGE OF ELECTRICITY USE FOR DATA CENTERS

Data Center Projections by State

North Dakota

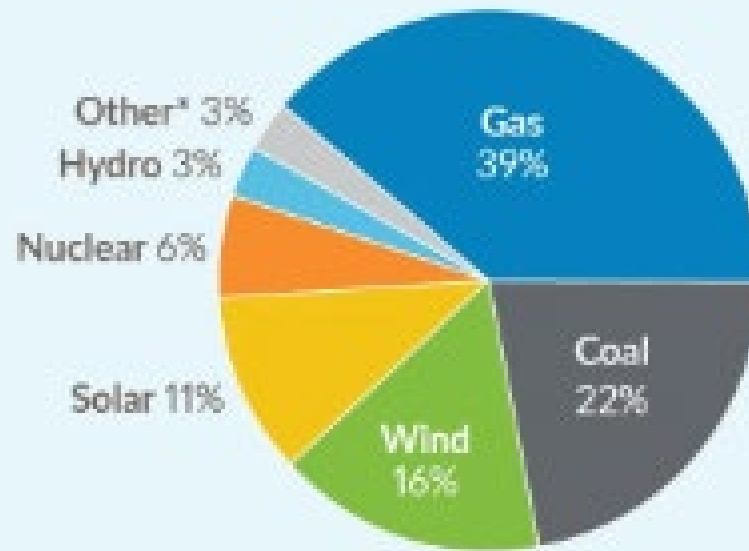


Source: <https://powering-intelligence.epri.com/executive-summary.html>

MID-CONTINENT INDEPENDENT SYSTEM OPERATOR (MISO)

INSTALLED CAPACITY

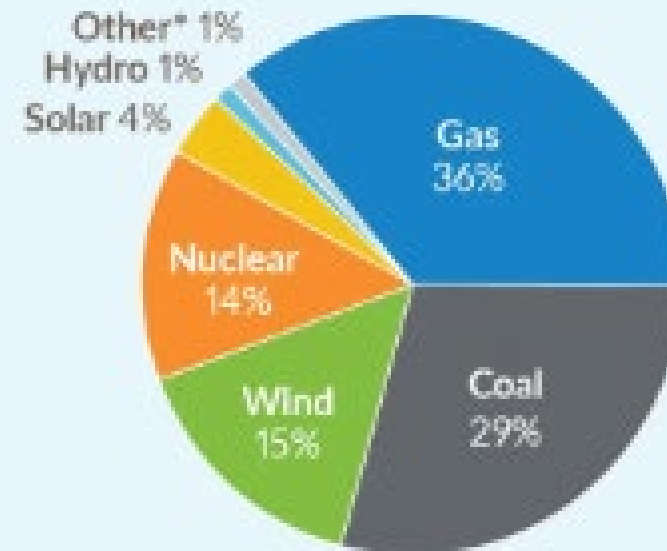
December 2025



207 GW

ENERGY PRODUCTION

January-December 2025



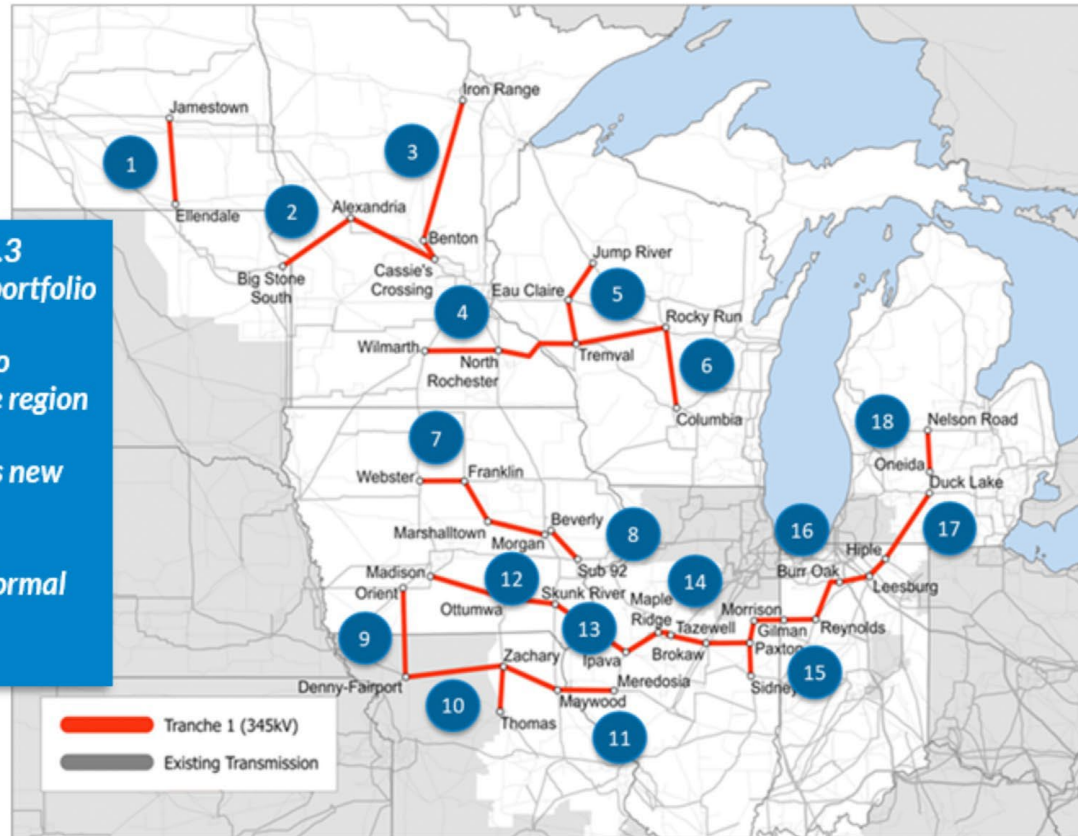
663 Million MWh

*Other: Diesel, Biomass, Storage, Demand Response Resources

MISO TRANCHE 1

MISO Board of Directors approved Tranche 1 in July of 2022 which included a 345kV portfolio across the footprint with widespread benefits

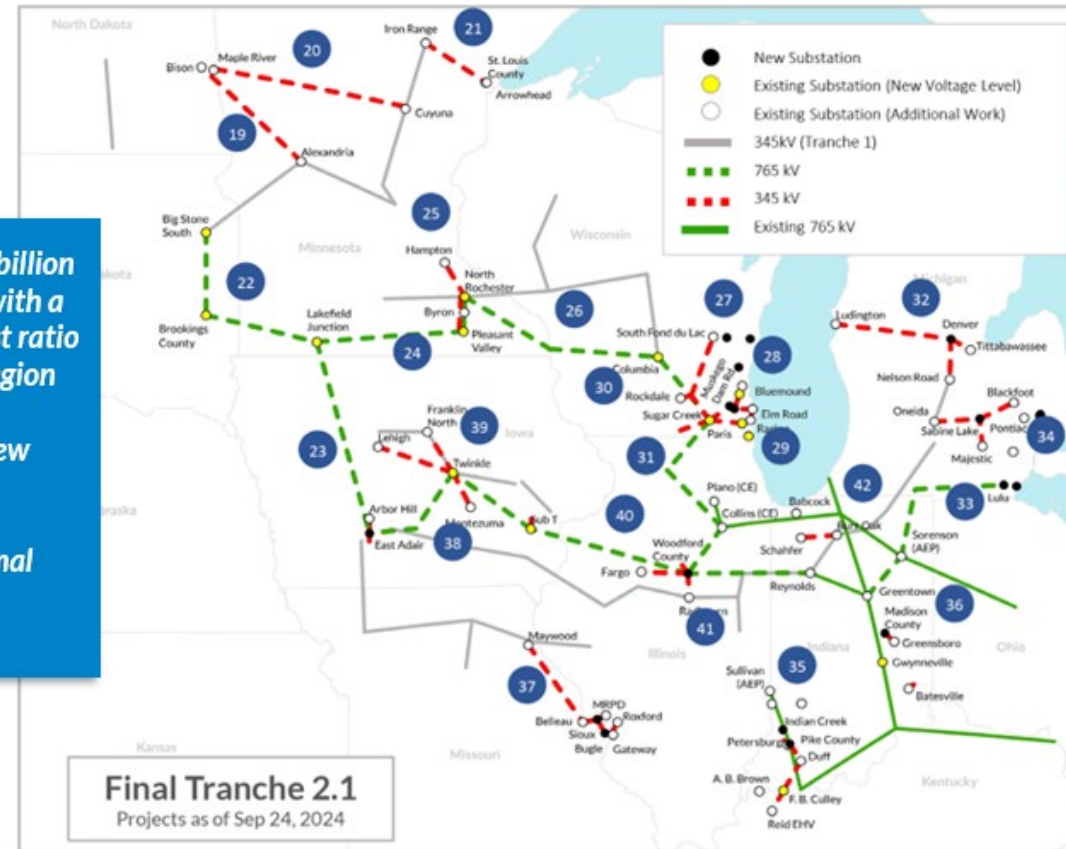
- 18-projects, \$10.3 billion Midwest portfolio with a 2.6-3.8 Benefit/Cost ratio spread across the region
- Over 2,000 miles new transmission
- More than 200 formal meetings



MISO TRANCHE 2.1

MISO Board of Directors approved Tranche 2.1 in Dec of 2024 which included a region-wide 765kV backbone with widespread benefits

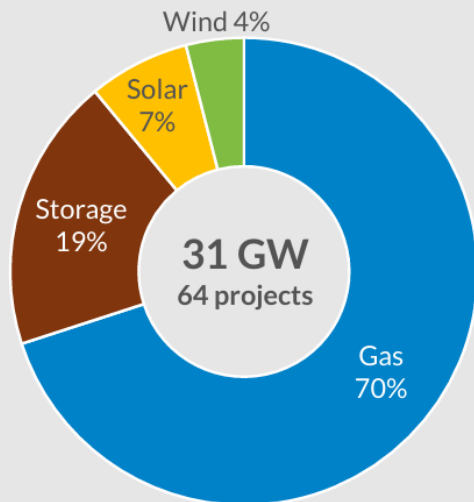
- 24-projects, \$21.9 billion Midwest portfolio with a 1.8-3.5 Benefit/Cost ratio spread across the region
- Over 3,600 miles new transmission
- More than 300 formal meetings



MISO's Long Range Transmission Planning: misoenergy.org/planning/transmission-planning/long-range-transmission-planning

MISO EXPEDITED RESOURCE ADDITION STUDY RESULTS

TOTAL ERAS APPLICATIONS



Quarterly Study Period 1	Complete, 10 projects (all LSEs), launched 9/2/25
Quarterly Study Period 2	Complete, 15 projects (all LSEs), launched 12/1/25
Quarterly Study Period 3	Complete, 15 projects (all LSEs), launched 3/2/26
Quarterly Study Period 4	Studies underway, 5 projects (all LSEs), launched 6/1/26
Quarterly Study Period 5	9 projects, launching 9/1/26
Quarterly Study Period 6	5 projects, launching 12/2/26
Quarterly Study Period 7	1 projects, launching 3/2/27
Quarterly Study Period 8	0 projects, last possible cycle could launch 6/1/27 prior to program sunset 8/31/27

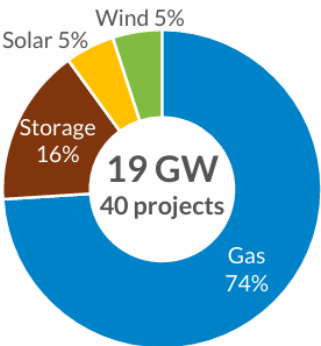
68 projects allowed:

- 10 Independent Power Producers
- 8 serving retail choice load
- 50 LSEs (no carve-out)

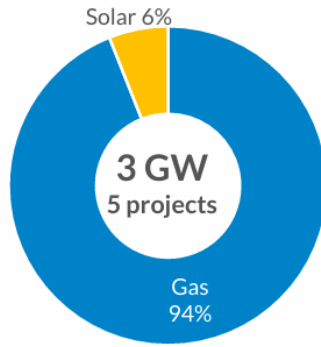
Applications to date:

- 13 Independent Power Producers (3 over cap)
- 0 serving retail choice load
- 51 LSEs (1 over cap)

APPROVED / NEAR-FINAL GIAs (Study 1, 2 and 3)

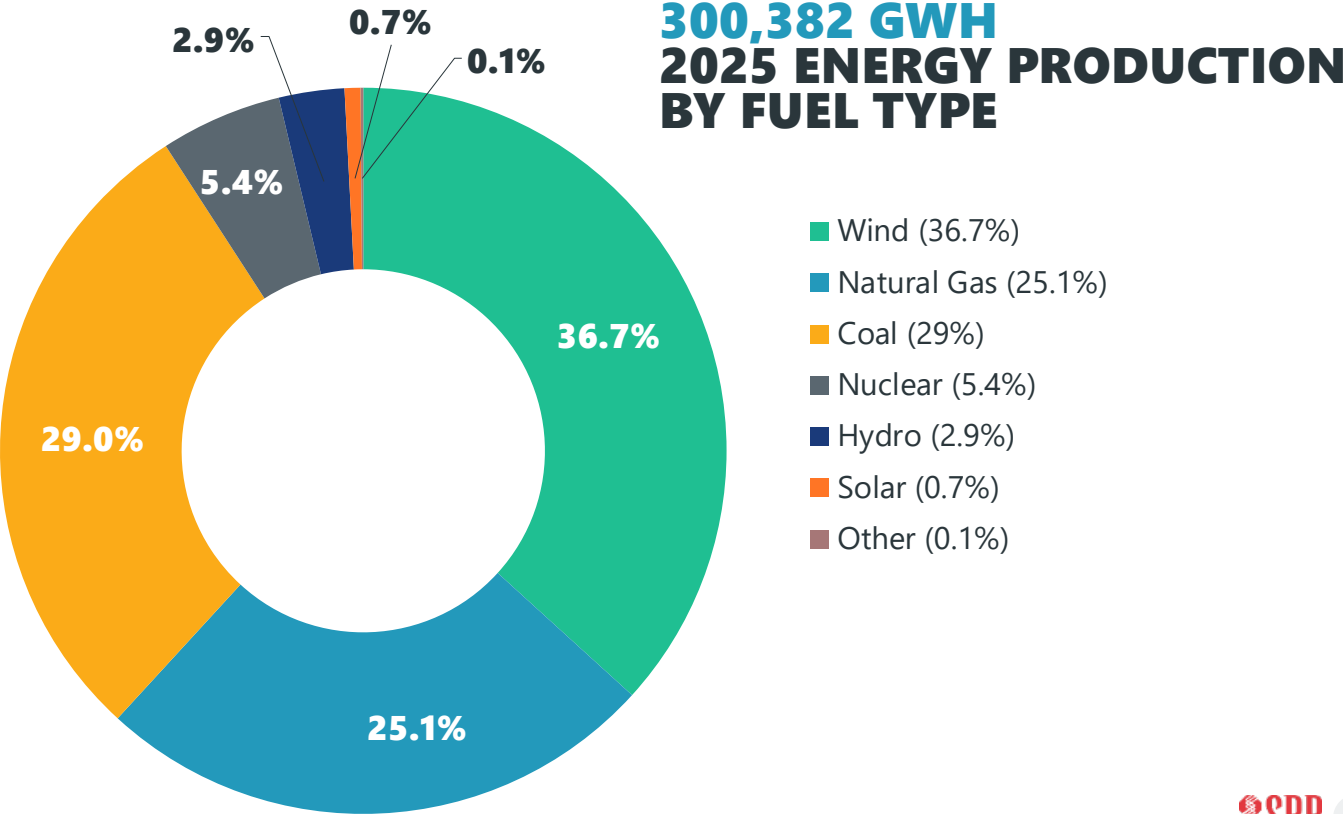


PROJECTS UNDER STUDY (Study 4)

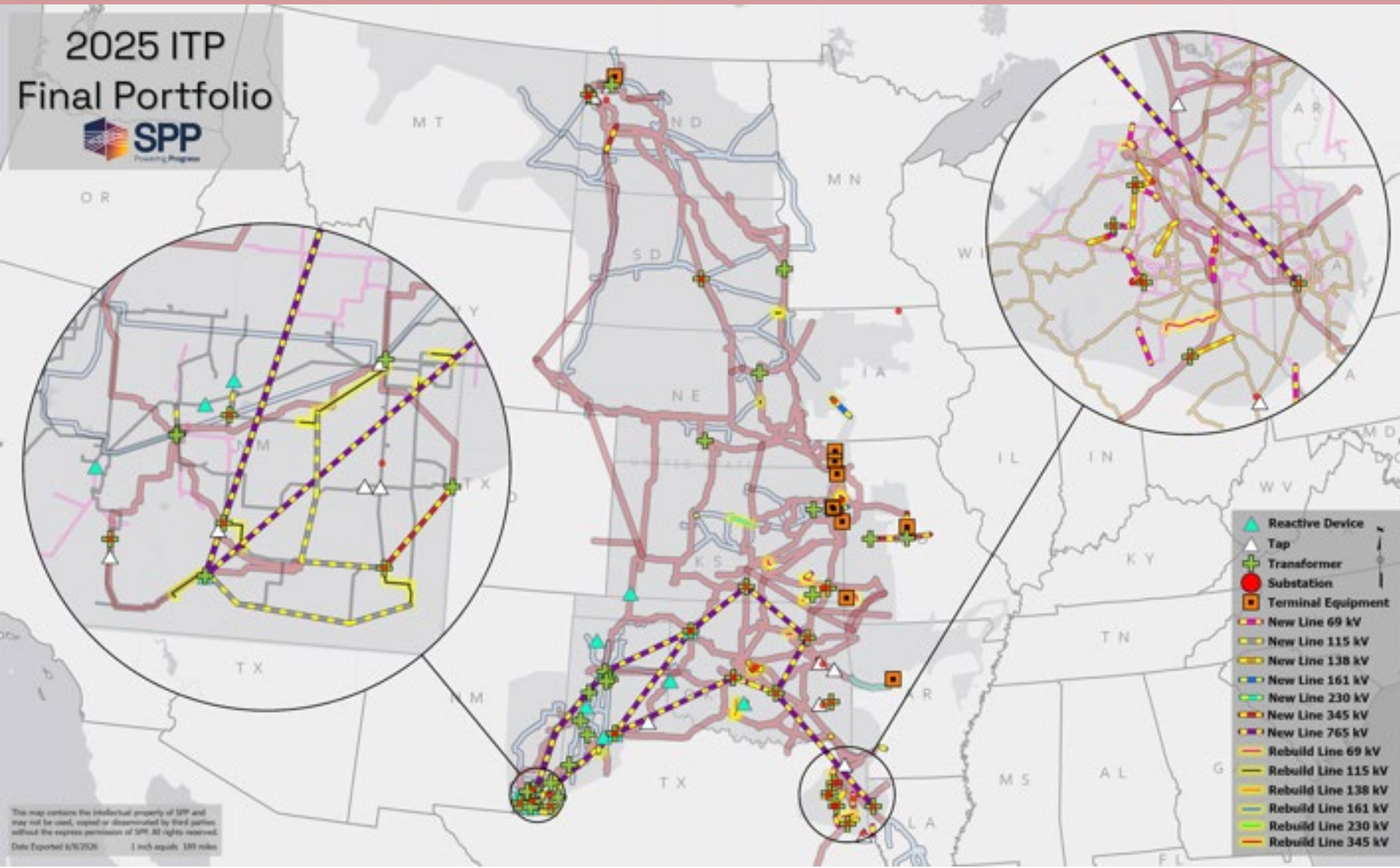


Data as of 7/08/26. All data reflects nameplate capacity LSE: Load-Serving Entity IPP: Independent Power Producer
ERAS: Expedited Resource Addition Study GIA: Generator Interconnection Agreement

SOUTHWEST POWER POOL (SPP) – 2025 ENERGY PRODUCTION



SPP INTRODUCING THE VISION OF A 765 KV BACKBONE



GRID UNITED – NORTH PLAINS CONNECTOR ...MERCHANT LINE

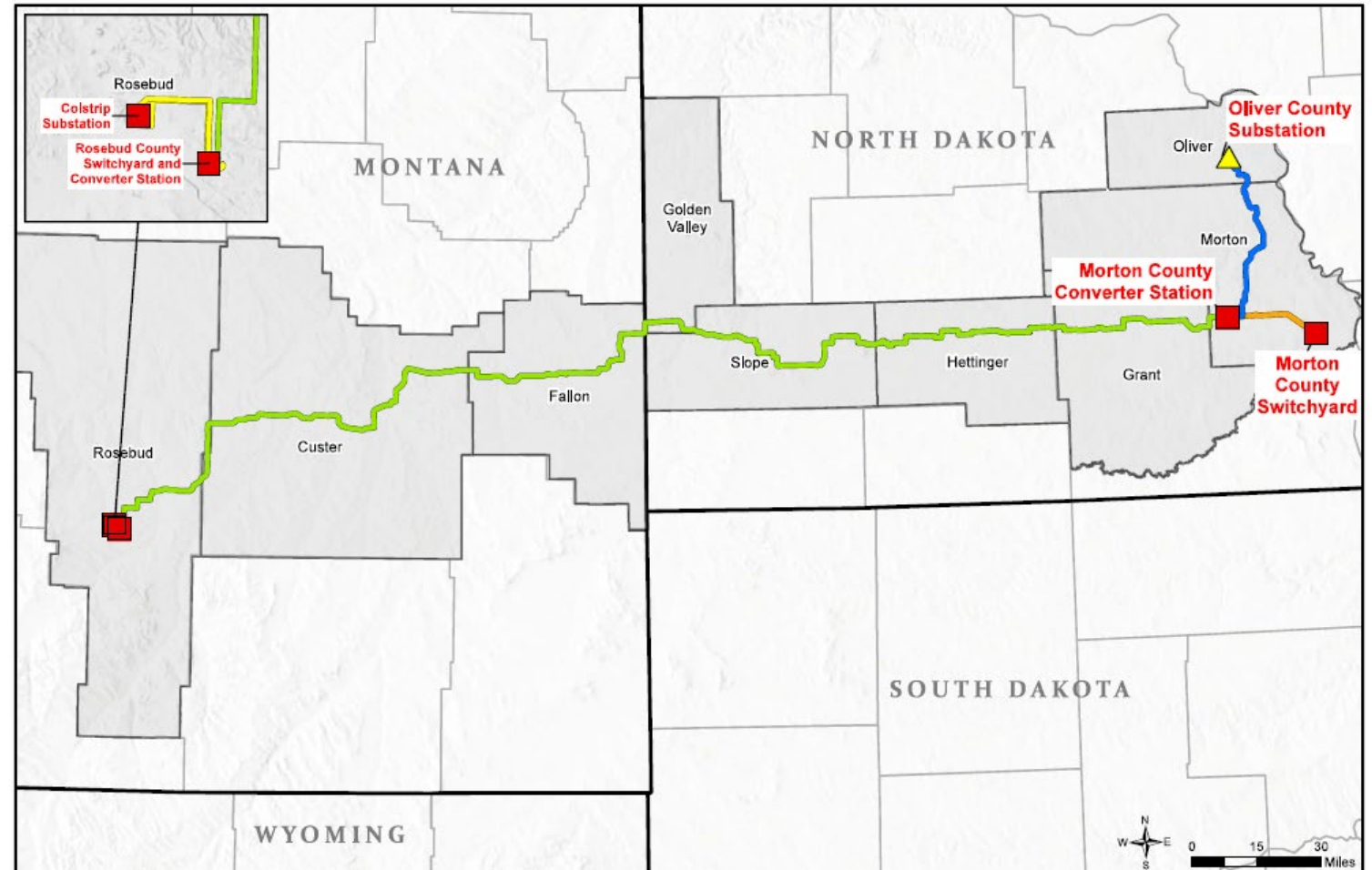
420 Mile HVDC Line

525 kV

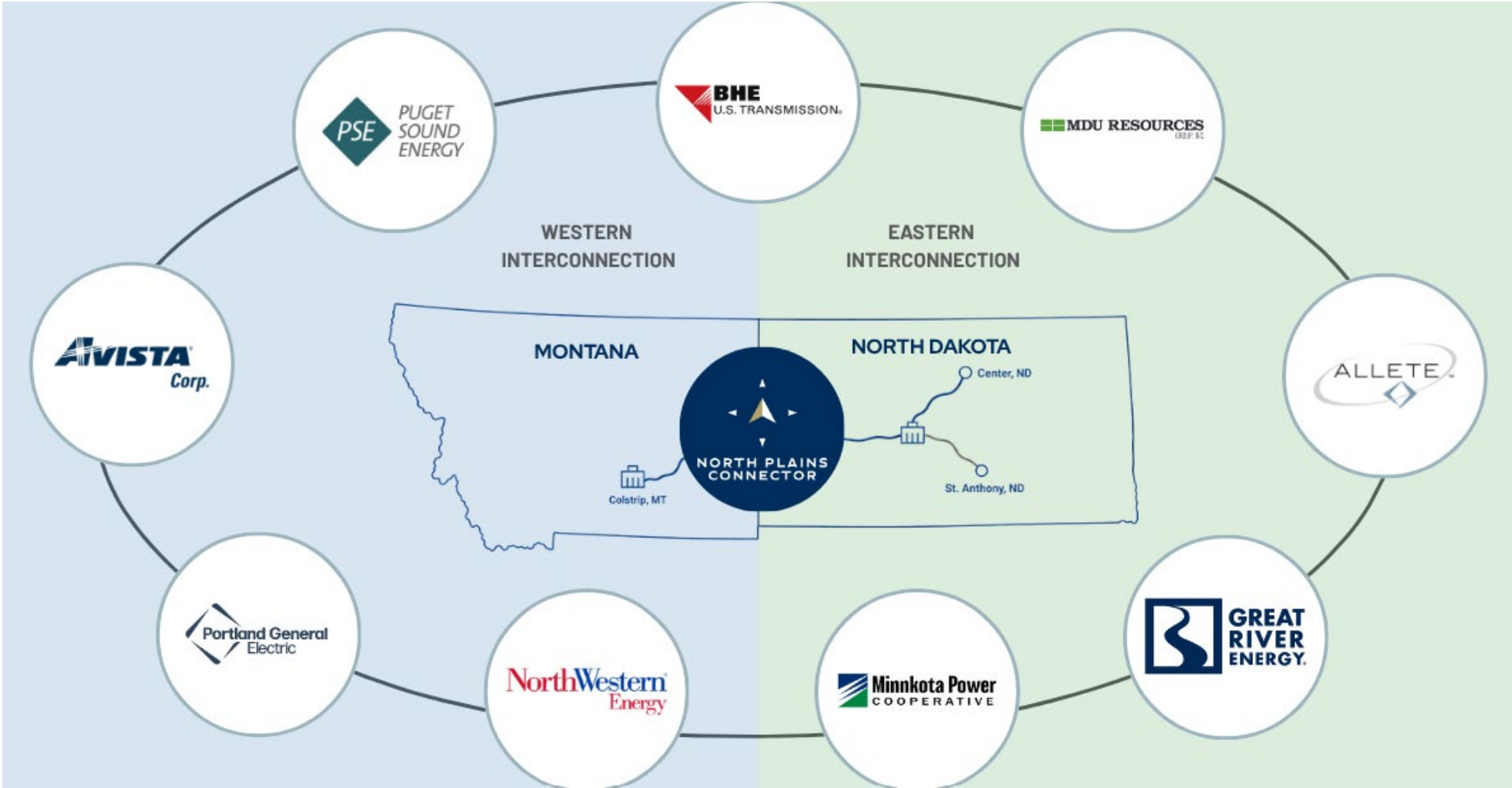
3,000 MW Capacity

Construction start 2028

In Service 2032



NINE UTILITY PARTICIPANTS



INCUMBENT UTILITY PROJECTS

North Plains Connector

Minnesota Power Allete

Minnkota Power

Basin Electric Power

MDU

Otter Tail

Xcel

Valley City Municipal

Grant Awards FY22/FY23/FY24

❑ Capital Electric Cooperative	\$ 321,930
❑ Otter Tail Power Company	\$4,432,088
❑ Northern Plains Electric Cooperative	\$ 586,000
❑ McKenzie Electric Cooperative (returned)	(\$2,843,075)
❑ Burke-Divide Electric Cooperative	\$ 550,000
❑ City of Lakota	\$1,707,109
❑ Verendrye Electric Cooperative	\$ 314,250
❑ KEM Electric Cooperative	\$ 620,000
❑ City of Valley City	\$ 715,468
❑ McLean Electric Cooperative	\$ 515,900
❑ Montana Dakota Utilities	\$2,086,488
❑ City of Northwood	<u>\$ 240,917</u>
	\$12,090,150

FY25 & FY26 IIJA GRANT FUNDS

- ❑ Still Waiting on DOE-NDIC Pre-approved Hillsboro & Lakota Projects
 - ❑ FY25 \$3,611,012 + 15% State Match
 - ❑ FY26 \$3,600,000 + 15% State Match

Applicant	Project	Grant Request	Total Cost
City of Hillsboro	Electric System Upgrades	\$4,226,250	\$5,635,000
City of Lakota	Substation Transformer/controls	\$2,589,750	\$3,453,000
TOTAL		\$6,816,000	\$9,088,000

N O R T H
Dakota

Be Legendary.

High Voltage
Transmission
765kV **345kV** 230kV

High Voltage
Direct Current
Transmission
525kV 400kV **250kV**

Sub-Transmission
115kV **60kV** 46kV
43.8kV 41.6kV **69kV**

REGIONAL
TRANSMISSION
OPERATORS

MIDWEST RELIABILITY
Organization

Interregional
T I E S



2026 ANNUAL REPORT



NORTH DAKOTA
TRANSMISSION
AUTHORITY

PREFACE

The North Dakota Transmission Authority (Authority) was created by the North Dakota Legislative Assembly in 2005 at the request of the North Dakota Industrial Commission. The Authority's mission is to facilitate the development of transmission infrastructure in North Dakota. The Authority was established to serve as a catalyst for new investment in transmission by facilitating, financing, developing and/or acquiring transmission to accommodate new lignite, wind, natural gas and other energy development. The Authority is a builder of last resort, meaning private business has the first opportunity to invest in and/or build transmission.

By statute, the Authority membership is comprised of the members of the North Dakota Industrial Commission. Claire Vigesaa was appointed Executive Director of the Authority in July 2023. The Executive Director works closely with the Industrial Commission Administrative Office staff and receives direct general fund appropriation.

NORTH DAKOTA INDUSTRIAL COMMISSION



KELLY ARMSTRONG
Governor



DREW H. WRIGLEY
Attorney General



DOUG GOEHRING
Agriculture
Commissioner

NORTH DAKOTA TRANSMISSION AUTHORITY



CLAIRE VIGESAA
Executive Director
ND Transmission Authority

Cover photos by Minnkota Power Cooperative

STATUTORY AUTHORITY

Statutory authority for the Transmission Authority is found in chapter 17-05 of the North Dakota Century Code. Section 17-05-05 N.D.C.C. delineates the powers of the Authority, including:

- 1) make grants or loans to borrow money
- 2) issue up to \$800 million in revenue bonds
- 3) enter lease-sale contracts
- 4) own, lease, rent and dispose of transmission facilities
- 5) enter contracts to construct, maintain and operate transmission facilities
- 6) investigate, plan, prioritize and propose transmission corridors; and
- 7) participate in regional transmission organizations.

Before the Authority may exercise its power to construct transmission facilities, it must follow a process defined by statute to ensure public participation and comment. In particular, the Authority must publish a notice describing the need for the transmission project. Entities interested in construction of the facilities or furnishing services to satisfy the identified needs have 180 days to respond by filing a notice of intent. If the Authority receives notice of intent from an interested entity, it may not exercise its power to construct unless the Authority makes a finding that doing so would be in the public interest. In making such a finding, the Authority shall consider the economic impact to the state, economic feasibility, technical performance, reliability, past performance, and the likelihood of successful completion and ongoing operation.

The Authority may finance approved projects through the issuance of bonds. Under current law up to 30 percent of the cost of a project may be financed by selling bonds that include the moral obligation of the State of North Dakota. In other words, up to \$240 million of the Authority's \$800 million total bonding authority may be sold with the moral obligation of the state. The moral obligation component enhances the marketability of the Authority's bonds.

TABLE OF CONTENTS

Executive Summary	4	Grid Reliability Challenges.....	12
Budget.....	6	Grid Enhancing Technologies (GETs)	14
Activities	7	Midwest Reliability Organization	14
Studies.....	9	Regional Transmission Operators (RTOs).....	16
Summary Reports.....	10	North Dakota Generation Projects	23
Grid Resilience Grants.....	11	North Dakota Transmission Projects	24

EXECUTIVE SUMMARY

North Dakota's electric grid is undergoing a pivotal transformation as it confronts the combined pressures of evolving energy demands, aging infrastructure, and the rapid integration of resources. Investment in transmission development has become a strategic necessity for sustaining grid reliability and long-term economic growth.

North Dakota's electric transmission system, the backbone of energy delivery, faces increasing strain from both supply-side and demand-side shifts. Historically designed to move electricity from coal-generating stations to neighboring states, the grid must now accommodate rising wind generation, new industrial loads, and regional export of power.

Major transmission initiatives, including multi-state high-voltage projects and grid modernization programs led by merchant developers, utilities and regional transmission organizations (RTOs) such as the Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP), aim to address congestion, enhance transfer capacity, and improve system flexibility. These investments are crucial for enabling energy development while maintaining reliability during extreme weather events.

Maintaining resource adequacy—ensuring sufficient generation to meet demand at all times—remains an evolving challenge. North Dakota's renewable growth has introduced variability that requires new capacity planning paradigms. While abundant wind resources contribute to a clean and affordable supply mix, intermittent output underscores the need for:

- Flexible generation resources such as natural gas, coal, nuclear, hydropower, and emerging storage technologies
- Expanded transmission to import and export power efficiently across regions
- Enhanced forecasting and demand response to manage peak loads and system imbalances

Proactive resource planning through MISO and SPP coordination will be central to managing seasonal adequacy and preserving reliability standards.

Extreme temperature events, such as polar vortices and heatwaves, have exposed vulnerabilities in fuel delivery systems and generator availability. Additionally, the aging transmission network faces physical and cyber threats that can compromise reliability. Key reliability challenges include:

- Transmission congestion
- Inadequate interregional transfer capacity
- Grid resilience under increasing severe weather conditions
- Supply chain and permitting delays for new infrastructure

Addressing these concerns will require both physical investments and regulatory collaboration to streamline project approvals and upgrade critical assets.

Despite these challenges, North Dakota is well positioned to lead in grid innovation and transmission development across the Upper Midwest. The state's unique combination of abundant coal and natural gas resources, strong wind resources, interest in carbon capture, and proximity to major market hubs create opportunities to:

- Expand oil/gas development, ag processing, data & AI centers in North Dakota
- Export energy through expanded high-voltage corridors
- Leverage grid-enhancing technologies to improve the efficiency of existing infrastructure
- Attract industrial investment from sectors seeking reliable, clean power
- Collaborate regionally to strengthen interconnections with neighboring states and markets

Strategic public-private partnerships, coordinated regional planning, and forward-looking policy frameworks will determine how effectively North Dakota capitalizes on these opportunities.

North Dakota's path forward in electric transmission development, resource adequacy, and grid reliability will define the state's energy future. By strengthening transmission infrastructure, diversifying generation portfolios, and enhancing interregional cooperation, North Dakota can ensure a resilient, affordable, and sustainable grid that supports economic growth and energy leadership across the Midwest.

Chair Vigesaa
Executive Director



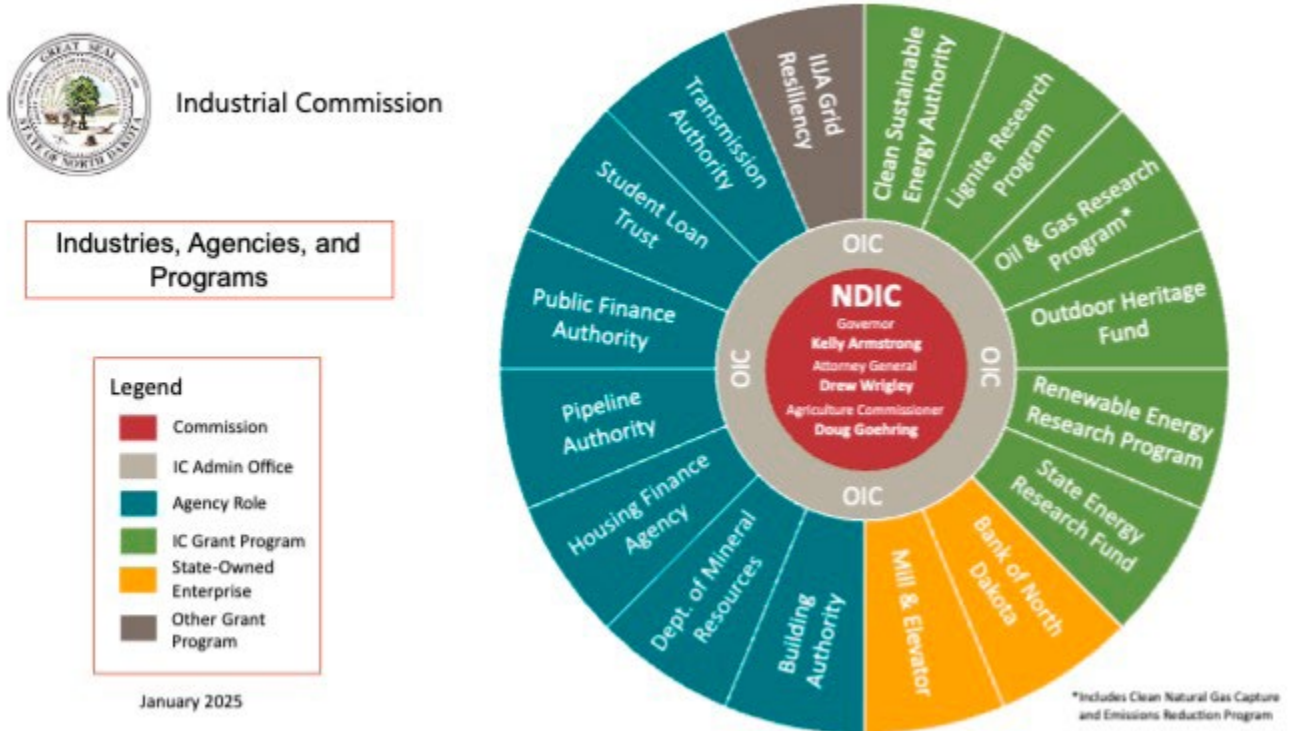
Photo by Carmen Dervay

*Vigesaa appreciates the guidance and support of the North Dakota Industrial Commissioners and Executive Director, **Karen Tyler**.*

BUDGET

The Transmission Authority is one of 16 agencies, authorities, enterprises and grant programs operated under the direction of the North Dakota Industrial Commission. Karen Tyler serves as the Executive Director of the Industrial Commission providing administrative guidance and support for the North Dakota Transmission Authority. The funding for the operation of the NDTA is within the general fund appropriation to the ND Industrial Commission.

The chart below shows the relationship between the ND Transmission Authority within the ND Industrial Commission's industries, agencies and programs.



The 69th ND Legislative Assembly appropriated \$400,000 to the ND Industrial Commission general fund budget to operate the NDTA for the 2025-2027 biennium. The Legislative Assembly also appropriated \$1,782,794 for the 15% match requirement for the IJA Grid Resiliency Formula Grant Program. This match enables North Dakota to access \$11,885,295 in DOE funds for grid enhancing project awards to utilities serving North Dakota consumers.

In its history, the NDTA has financed one project, Rainbow Energy's purchase of the NEXUS HVDC line that originates at Coal Creek Station and terminates in the Minneapolis area. The bond financing's term is 20 years with interest at a rate of 3.55% per annum secured by the mortgaged property.



ND Industrial Commission staff **Karen Tyler**, Executive Director and **Andi Rebsom**, Fiscal Manager discuss ND Transmission Authority finance with Executive Director, **Claire Vigesaa**.

Photo by Carmen Devrey

ACTIVITIES

The ND Transmission Authority seeks to facilitate open communication among policymakers, regulators, state agencies, regional transmission organizations, developers and the electric utility industry. Open communication and shared vision provide for efficient and effective transmission expansion for a reliable and affordable grid. The NDTA is available to present to associations, communities, and other entities upon request. The NDTA fields regular calls from ND Legislative Leadership, trade associations and community leaders. The NDTA presented and/or participated in the following events/associations this past year:

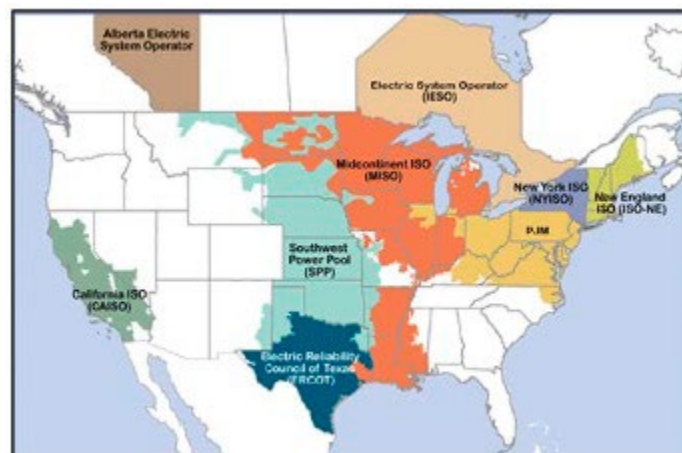
Spiritwood Energy Park Tour – Hosted by Rachel Retterath, Great River Energy
Clean Sustainable Energy Authority – Technical Review Committee & Board Meeting
UND Energy Hawks Student Group – Presenter
NDSU Bison to Bakken Student Group - Presenter
Stutsman County Zoning Committee – Set Back Issues - Testified
Energy & Environmental Research Center Tour – Hosted by Brad Stevens & Daisy Selvaraj
BNI – Minnesota Power Allete Educational Event – Hosted by Mike Heger & Cheryl Froelich
ND Energy Development & Transmission Interim Meeting – Ellendale - Rep Anna Novak, Chair - Presented
ND PSC Educational Events with MISO & SPP
Great River Energy Transmission Plan Update – Host Owen Henrickson
ND Department of Commerce – Quarterly Energy Meetings
Advanced Nuclear Energy Interim Legislative Committee – NDIC Designated Committee Member
NDAREC Policy Update – Josh Kramer
National Governor’s Association Energy Policy Institute – Boston
National Governor’s Association Transmission Summit – Boston
Great Plains Collaborative Committee (one of 11 states) – Committee Member
North Plains Connector Public Information Session – New Salem
ACORE Grid Forum – Washington, D.C.
Rainbow Energy – Nexus Transmission Line Update – Stacy Tschider/Jessica Bell - Hosts
ND Energy Development & Transmission Interim Meeting – Bismarck
Conoco Phillips Management Grid Discussion – Brady Pelton, ND Petroleum Council
Minnesota Power Allete Project Update – Julie Pierce
Lignite Energy Council Annual Meeting – Bismarck
ND PSC Emmons/Logan Battery Storage Hearing – Linton
Basin Electric Power Cooperative Load Forecasting Discussion – Jay Lundstrom - Host
Midwest Governors Association Mid-GRID 2035 Meeting – Columbus, OH - Presenter
Collaborate Advancing Rapid Load Addition – DOE Application Submission
PSC Technical and Public Hearings for JETx Project - Testimony
Dakota Morning Radio Show – Alison Ritter – Host - Guest
National Association of State Energy Offices – Transmission Summit - Arlington VA – Presenter
North American Electric Reliability Corporation Grid Reliability Technical Workshop – Washington D.C.
US Energy Association Coal Workshop – Bismarck
Minneapolis MISO Operations Center Visit – Bridget Docktor & Brian Tulloh - Hosts
Advanced Nuclear Energy Committee Meeting – Idaho National Laboratory, Idaho Falls, ID
Western Dakota Energy Association – Watford City – Presenter

ND Society of Professional Engineers – ND Chapter - Grand Forks - Presenter
Midwest Reliability Organization Summit – Omaha, NE
DOE SPARK Application – Lead Applicant & Advisory Committee
ND Interim Energy Development and Transmission Meeting – Grand Forks – Presenter
Energizing North Dakota Energy – Grand Forks

Midwest Governors Association (MGA): The MGA established an initiative (MID-GRID 2035) for regional transmission education and planning to position the Midwest as a modern energy producer and low-cost energy provider, with the goal to establish a long-term transmission grid vision for the region. The NDTA participated in conferences held by the MGA, MID-GRID 2035 quarterly meetings including a conference in Columbus, OH. The 2026 MGA Transmission Summit will be held in Bismarck on July 8-9, 2026. In addition, the NDTA participated in Transmission Conferences hosted by the National Governor’s Association in Boston, MA, and a National Association of State Energy Offices in Washington, D.C. As executive director, I also participate in the Great Plains Collaborative Energy Discussions.

Midwest Reliability Organization (MRO): On October 25, 2023, the NDTA became a member of the MRO in the Adjunct Sector. MRO’s primary responsibilities are to ensure compliance with mandatory reliability standards by entities who use, own or operate the North American bulk power system; conduct assessments of the grid’s ability to meet electric power demand in the region; and analyze regional system events. Additionally, MRO creates an open forum for stakeholder experts in the region to discuss important topics related to addressing risk and improving reliable operations of the grid. MRO serves as a vital link between grid owners, users, operators, and other stakeholders who share common reliability interests in the region. The organization presents opportunities to learn with electric grid operators in the region. Board representatives from our constituents include Darcy Neigum-MDU, JoAnn Thompson-Otter Tail Power Company, Lloyd Linke-WAPA, Priti Patel-Great River Energy, and Sandra Johnson-Xcel Energy.

Regional Transmission Organizations: As shown on the map that follows, North Dakota is served by two regional transmission organizations, Mid-Continent Independent System Operator (MISO) and the Southwest Power Pool (SPP). The NDTA attends numerous committee meetings for both MISO and SPP to keep abreast of initiatives that impact grid reliability, particularly for North Dakota. Both RTOs are undergoing transformative policy and procedural process changes due to significant load growth, changing generation mixes and transmission development.



STUDIES

LARGE LOAD IMPACT STUDY ON NORTH DAKOTA

The NDTA commissioned the Energy & Environmental Research Center (EERC) and Power Systems Engineering to develop an analytical framework for supporting near-to-long-term planning and decision making around key issues facing North Dakota's electricity sector. Key issues investigated included the impacts of a changing resource mix, new policies and regulations affecting coal-based electricity, increasing penetration of renewable sources, lead times for transmission infrastructure build-out, and load growth on resource adequacy and electric reliability within the state as well as the regional grid. The final report was completed in the 3rd quarter of 2025. The study placed large loads in three regions of the state: 1,400 MW-East, 1,100 MW – Central and 600 MW -West. Through integrated reliability and economic analysis, the study evaluated how large-load additions influence transmission loading, system reliability, transmission congestion, electricity market prices, generation dispatch and renewable generation and curtailment. The study showed that additional large-load scenarios caused the number of thermal and voltage violations to increase significantly. The study underscores that coordinated generation and transmission development will be required to add significant large-load projects to the grid. The study results were shared with the ND Energy Development & Transmission Interim committee, the ND PSC, SPP, MISO and the industry.

COLLABORATIONS ADVANCING RAPID LOAD ADDITIONS

In August 2025, the North Dakota Industrial Commission, acting as the North Dakota Transmission Authority, submitted a concept paper to DOE for Collaborations Advancing Rapid Load Additions (CARLA). In December we were invited to submit a full application. Organizations/Key Personnel involved in the project include:

North Dakota Industrial Commission acting as the ND Transmission Authority-Claire Vigesaa
Southwest Power Pool – Jake Dubbs
Midcontinent Independent System Operator – Bridget Docktor
Applied Digital – Nick Phillips
University of Illinois Urbana-Champaign – Leslie M. Gioja, PE
Hafiz Salih, PhD
Energy & Environmental Research Center – Brad Stevens, PE; Daisy Selvaraj, PhD
Power System Engineering – vendor

This project seeks to develop new approaches and frameworks for system planning, cost recovery, and risk analysis for electricity demand growth to facilitate rapid near-term load additions while minimizing or preventing rate increases for customers. The work includes evaluating the current electrical grid in North Dakota to assess the current grid capacity for future large load additions, as well as assessing the current procedures for load, generation and transmission capacity to identify bottlenecks and potential solutions that may provide visibility to more affordable load pocket areas. This could ultimately reduce or eliminate the current data scouting challenge, maintain grid reliability, and still enable data center growth.

The specific project goals are to: (1) assess the current and near-future demand and generation profile of North Dakota; (2) identify available capacity for new projects and potential areas for future interconnections; (3) assess the grid planning process and procedures to identify bottlenecks or challenges; (4) perform what-if scenario analyses to evaluate risks and mitigation strategies associated with the time lag between demand and asset approval and construction; and (5) propose potential improvements to process and procedures, which will facilitate more accurate demand and generation projections and reduce interconnection queue times.

The proposed project budget request (no match required) is \$4,814,906. If awarded, the project would quickly engage electric utilities serving in North Dakota and the ND PSC for the two-year study period.

ND LEGISLATIVE INTERIM ADVANCED NUCLEAR ENERGY COMMITTEE

The 69th North Dakota Legislature initiated two bills that support nuclear generation studies. Senate Bill 2159 authorized study by removing a prohibition against EERC studying nuclear energy that was in section 15-11-40 (4) of the North Dakota Century Code. SB 2159 was a companion bill to HB 1025. HB 1025 was a Legislative

Management Study – Advanced Nuclear Energy. This bill sets up a study for the 2025-26 interim. Legislative management shall study the feasibility, siting and deployment of advanced nuclear power plants in the state. The Study will consider siting, grid connectivity, land use considerations, economic impacts, temporary and permanent nuclear waste store, small modular and micro nuclear reactors and provisions of the North Dakota Century Code that place restrictions on advanced nuclear energy development, if any.

The ND Legislative Interim Advanced Nuclear Energy Committee engaged Nucleon to provide five reports:

1. Siting and Land Use Report – December 2025
2. Economic Impacts & Private Sector Financing Report – March 2026
3. Nuclear Waste Storage Assessment Report – March 2026
4. Technology Assessment & Feasibility Report
5. North Dakota Century Code Report



The Advanced Nuclear Energy Interim Committee held a committee meeting at the Idaho National Laboratory (INL) in April 2026. The two-day event was filled with informative presentations and facility tours by INL Leadership. Photo Credit - INL Communications Department.

GRID RESILIENCE GRANTS

IIJA SECTION 40101(D) FORMULA GRANTS

FY22-FY23 Grant Subrecipients

Capital Electric Cooperative	\$ 321,930
Otter Tail Power Company	\$4,432,088
Northern Plains Electric Cooperative	\$ 586,000
McKenzie Electric Power Cooperative	\$2,843,075 (returned)

FY24 Grant Subrecipients

Burke-Divide Electric Cooperative	\$ 550,000
City of Lakota	\$1,707,109
Verendrye Electric Cooperative	\$ 314,250
KEM Electric Cooperative	\$ 620,000
City of Valley City	\$ 715,468

FY24 (dollars not used by Valley City) Awarded 11/2025

City of Northwood	\$ 240,917
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Northern Plains Electric Cooperative completed their IIJA grant project in April 2025, the installation of several SCADA ready reclosers. The state of the art recloser control panel and a completed substation are pictured above.



Carmen Devney, NDIC Grant Program Specialist and **Jordan Kannianen**, NDIC Deputy Executive Director, congratulate **Greg Owen**, Capital Electric Cooperative Manager of Engineering for completing their IIJA Grant project in January 2025. Capital's project consisted of converting state highway power line crossings from overhead to underground.

GRID RELIABILITY CHALLENGES

The US electric power system is entering a period of rapid and transformational change due to:

- Re-shoring of industrial activity
- Unprecedented surge in demand for data centers and artificial intelligence
- Accelerating electrification of buildings and transportation
- Aging grid and generation infrastructure

Meeting this demand will require significant investments in grid infrastructure, which can be costly and take a long time. The key question is how can utilities, system planners, policymakers, and regulators collaborate to serve new loads more quickly and cost effectively, while still meeting state and corporate energy goals reliably and affordably?

Each year, NERC is responsible for independently assessing and reporting on the overall reliability, adequacy, and associated risks that could impact the upcoming summer and winter seasons, as well as the long-term, 10-year period. As emerging risks and potential impacts to reliability are identified, special assessments are conducted that provide similar technical framework and insights about the range and specific aspects of these to guide steps that may be warranted. Unbiased judgment of industry's plans for maintaining electric reliability in the future are founded on solid engineering through collaborative and consensus-based assessments.

By identifying and quantifying emerging reliability issues, NERC can provide risk-informed recommendations and support a learning environment for industry to pursue improved reliability performance. These recommendations, along with the associated technical analysis, provide the basis for actionable enhancements to resource and transmission planning methods, planning, and operating guidelines, and NERC Reliability Standards. The graphic below demonstrates the Risk Area Summary 2026-2030 in NERC's 2025 Long-Term Reliability Assessment.

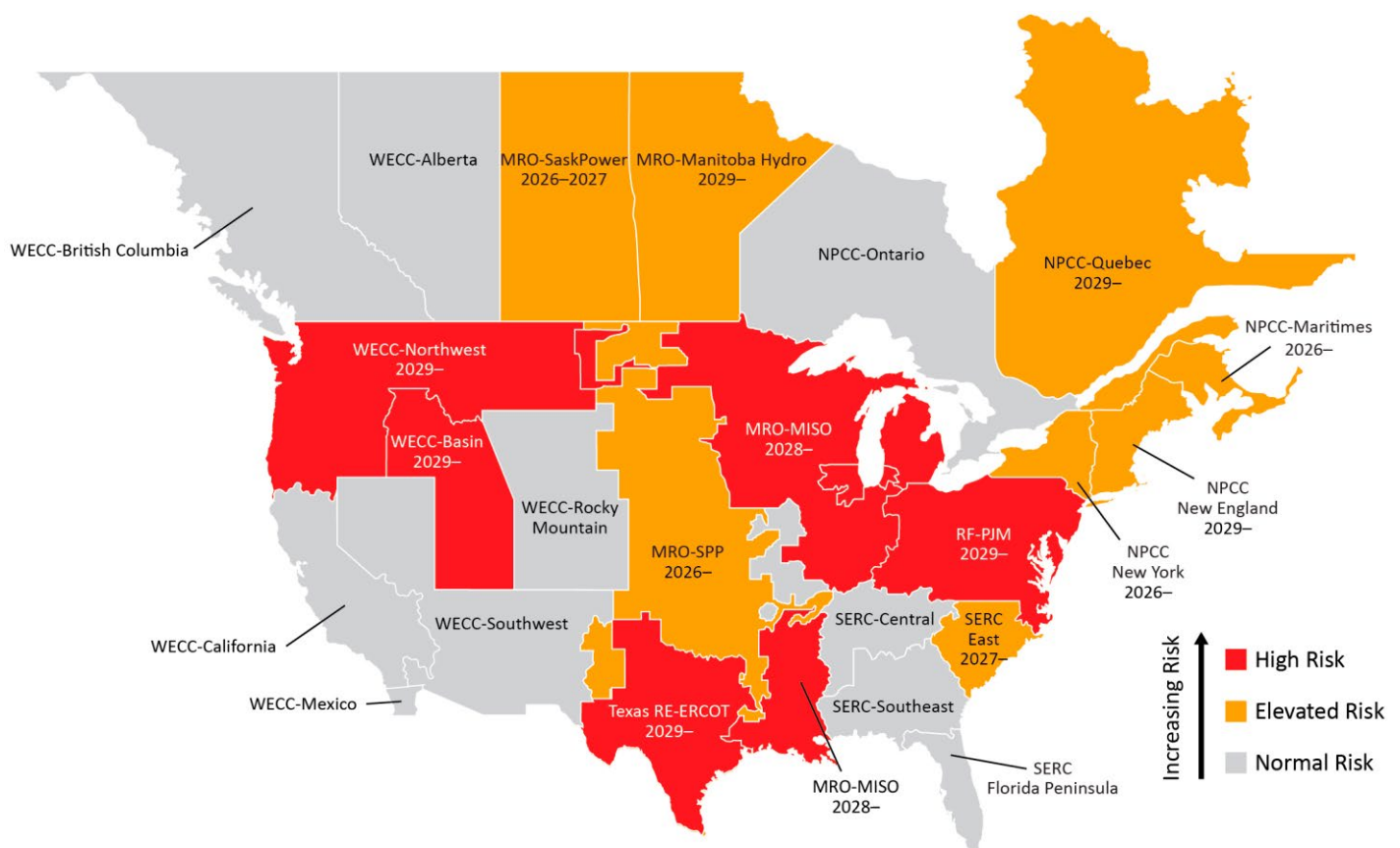


Figure 1: Risk Area Summary 2026–2030

Shows highest risk classification that occurs in the first 5 years and states initial year of occurrence

In addition to the challenges of planning, cost allocation, building and operating; siting, landowner and public acceptance of large-scale projects and linear infrastructure is increasingly difficult. Communication and collaboration with communities and landowners needs to start early and often.

It will require full engagement of industry, policymakers and regulators to expeditiously develop generation capacity and transmission assets to meet load growth. Although there has been movement on regulatory relief here in the USA, global competition for transmission and generation building materials and equipment will present challenges for developers. That leads to the critical challenge of timing, failure to get generation and transmission in place to meet industry expectations will limit economic growth as well as hinder grid reliability.

GRID ENHANCING TECHNOLOGIES (GETs)

A future-ready grid requires infrastructure built with the latest technologies, including everything from complex devices compatible with digital technology to fundamental capabilities, such as mapping out the flow of electricity. Grid-enhancing technologies (GETs) maximize the electricity transmission across the existing system through a family of technologies that includes sensors, power flow control devices, and analytical tools.

GETs are gaining traction and have the advantage of speed...compared to the time to build transmission! GETs enables increased transmission capacity, reduces congestion and accelerates generation integration. Great River Energy has one of the largest deployments of drone-installed dynamic line rating sensors in the USA. WAPA and Basin Electric Power Cooperative collaborated on the installation of DLR on WAPA's 230kV transmission line near Watford City. There are three major GETs solutions:

1. **Dynamic Line Ratings (DLR)** – Real-time monitoring of transmission line capacity based on environmental conditions.
 - a. *Real-time capacity monitoring: DLR adjusts transmission line ratings based on temperature, wind speed and grid conditions.*
 - b. *Reducing congestion costs: DLR can unlock up to 60% more capacity, reducing charges and energy costs.*
 - c. *Enhancing Grid Reliability: Accurate, dynamic ratings improve operational decisions and prevent overload risks.*
 - d. *Support Generation Integration: DLR allows greater utilization of generation by adapting to environmental conditions.*
2. **Advanced Power Flow Control (APFC)** – Optimizes power distribution using modular power electronics to enhance grid flexibility.
 - a. *Optimizing Power Distribution: APFC dynamically adjusts power flow across transmission lines, reducing congestion.*
 - b. *Enhancing Grid Stability: APFC mitigates voltage fluctuations and supports frequency regulation.*
 - c. *Modular and Scalable Deployment: APFC solutions can be installed incrementally and redeployed as needed.*
 - d. *Reducing Infrastructure Costs: APFC minimizes the need for costly new transmission lines by improving existing capacity.*
3. **Topology Optimization Software (TTO)** – Reconfigures grid topology to reduce congestion and improve transmission efficiency.
 - a. *Dynamic Grid Reconfiguration: Software-driven topology changes optimize power flows and reduce congestion.*
 - b. *Minimizing Renewable Curtailment: Topology optimization ensures maximum utilization of renewable generation.*
 - c. *Fast and Cost-Effective Deployment: Unlike physical upgrades, software-based solutions can be rapidly implemented.*
 - d. *Enhancing Operational Flexibility: Operators can quickly adjust grid configurations to improve efficiency and resilience.*

MIDWEST RELIABILITY ORGANIZATION (MRO)

More than 260 organizations participate in the production and delivery of electric power, serving approximately 28 million people in MRO's region. These companies are required to comply with mandatory NERC Reliability Standards and requirements, which MRO oversees. Membership with MRO is voluntary, free of charge, and is not based on a company's NERC registration status. MRO has two classes of members: Adjunct Members (The ND Transmission Authority is in this category) and Industry Members that qualify for one of seven industry sectors. Industry Sector Members are allowed to participate on the board of directors and MRO's organizational groups. Currently, MRO

has 105 members, including 13 Adjunct Members. The 23-member hybrid board of directors includes four independent directors, two regional directors, and seventeen industry sector directors. The independent and regional directors are elected by all members, and the industry sector directors are elected by the seven sectors those directors represent. The board's Organizational Group Oversight Committee—a sector-based group of board members—oversees MRO's advisory councils and subgroups. The purpose of the organizational groups is to provide a forum for stakeholders across the region to discuss risk, develop risk mitigation strategies, expand outreach and awareness, promote information-sharing, and publish guidance for the region.

The MRO's 2026 Regional Risk Assessment identified the top six risks to reliable and secure operation of the regional bulk power system. The risk level and descriptions follow:

1. **Extreme: Uncertain Energy Availability:** *Increasing electricity demand coupled with rapid retirement of traditional power plants creates potential energy shortfalls. This is especially true when replacement generation is variable, weather-dependent and may not be available when needed.*
Drivers: *Legislative policies, generator retirements, new resource constraints, demand growth, inadequate transmission.*
2. **High Nation-State Threats:** *The strategic objections of nation-state-sponsored actors from China, Russia and Iran pose significant cyber threats to the North American bulk power system. Their objectives vary but generally aim to weaken our military and economic systems.*
Drivers: *Heightened geopolitical tensions, increasing sophistication of threat actors, insufficient internal controls.*
3. **High: Generation Outages During Extreme Cold Weather:** *The electricity grid faces significant challenges during extreme cold weather, which occurs more often and with greater intensity and duration. Recent events resulted in unprecedented customer load shed to maintain system stability.*
Drivers: *Insufficient winterization, lack of fuel supply, gas/electric interdependencies, generator retirements.*
4. **High Supply Chain Compromise** *Occurs when a vendor is the vector for a threat actor who manipulates hardware, software, connected services, or software delivery mechanisms for financial gain. The risk is amplified by the limited number of vendors serving the industry.*
Drivers: *Supply chain complexity, growing reliance on third-parties, lack of third-party controls and visibility.*
5. **High Inadequate IBR and DER Performance and Modeling:** *Inverter-Based Resources (IBRs) and Distributed Energy Resources (DERs) -wind, solar and battery—are a relatively new technology for generating electricity. Industry and manufacturers are learning how to reliability integrate these resources into the power grid.*
Drivers: *Increasing reliance on IBRs to serve load, lack of visibility, lack of experience with technology.*
6. **Material and Equipment Unavailability:** *National and world-wide electric demand is creating high demand for generation and transmission components; demand is greater than domestic/international manufacturing can produce in a timely manner.*
7. **High Malicious Insider Threat:** *Malicious insiders (employees, vendors, contractors) with access to critical systems and intent to do harm, can disrupt bulk power system operations. This risk does not include insider intelligence.*
Drivers: *Limited detective controls in place, lack of insider threat programs.*



Claire Vigesaa, Executive Director-NDTA, invited to participate in NERC's Reliability Workshop in Washington D.C. March 2026.

REGIONAL TRANSMISSION OPERATORS (RTOs)

North Dakota is served by two RTOs, Midcontinent Independent System Operator (MISO) and the Southwest Power Pool (SPP).

The MISO footprint covers the service territories of Otter Tail Power (OTP), Montana-Dakota Utilities (MDU), Great River Energy (GRE), Xcel Energy, Missouri River Energy Services (MRES), and a small amount of transmission assets owned by Upper Missouri Power Cooperative. In addition, MISO has an agreement with Minnkota Power Cooperative that provides them with many of the same services. Western Area Power Administration (WAPA) and Basin Electric Power Cooperative (BEPC) are members of the Southwest Power Pool. SPP BEPC members Mountrail-Williams Electric Cooperative, Central Power Electric Cooperative, Roughrider Electric Cooperative and Mor-Gran-Sou Electric Cooperative have also joined SPP individually due to their transmission ownership.

MISO and SPP also operate the power markets in their respective territory. Pricing for selling electricity into the grid and for buying electricity from the grid is managed by them. This process determines which generating units that have been bid into the market by Market Participants (MP) will be providing generation at any point in time and which units will provide various ancillary services to sustain voltage, assure reliability, etc.

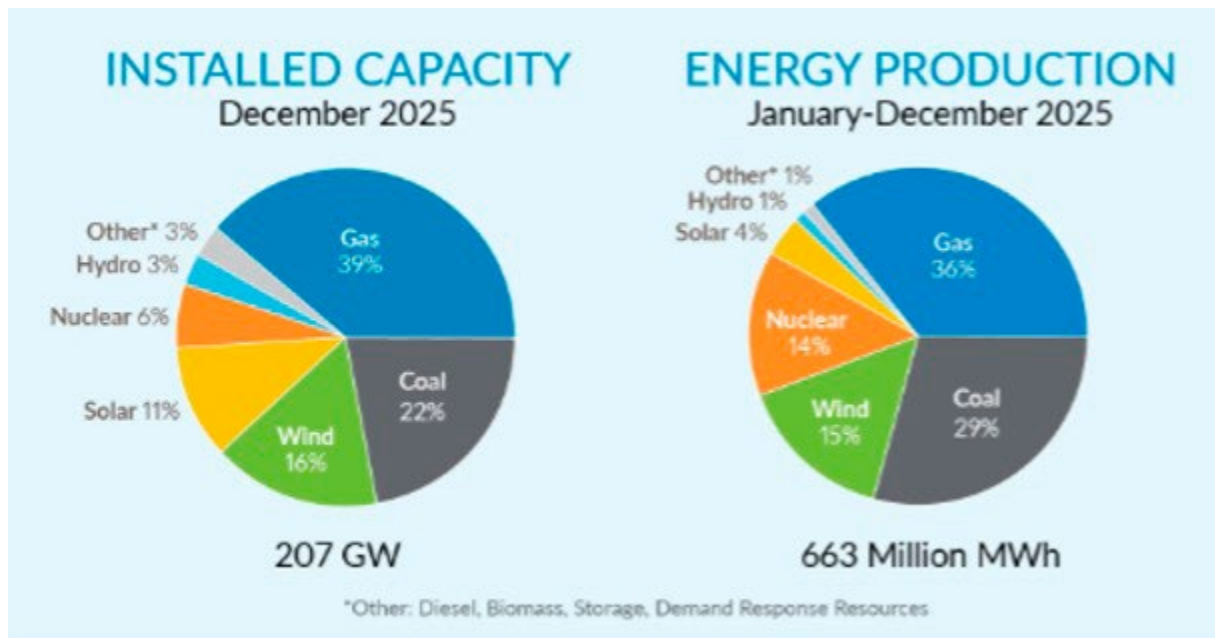
WAPA is the Transmission Operator for the SPP transmission network in North Dakota. ND PSC Commissioner Randy Christmann serves on the SPP Regional State Committee. ND PSC Commissioner Jill Kringstad represents the ND PSC on the MISO Advisory Committee. Victor Shock, Director, Public Utilities Division, and PSC staff Chris Hanson, Leif Clark, Robert Frank and Adam Ranfandt participate in RTO committee work.

Both MISO and SPP acknowledge the Administration's support for baseload generation and the pressure relief (proposed EPA regulations) on coal and fossil fuel generation. Avoiding premature shutdown of coal facilities will provide much needed capacity for demand growth. SPP and MISO have both implemented expedited resource study approaches to speed the interconnection queue process, adding much needed new generation capacity to the grid.

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR (MISO)

MISO manages the flow of electricity across 15 U.S. states and the Canadian province of Manitoba, serving a population of 45 million with 79,000 miles of transmission lines in its network. MISO's peak demand of 127.1 GW occurred on July 20, 2011.





MISO'S RELIABILITY IMPERATIVE

MISO's "Reliability Imperative" addresses the shared responsibility the regional transmission organization, the states, and members must navigate the challenges of the electric grid within the MISO region. This includes planning for large load additions, tightening reserve margins, and working to decrease the interconnection queue length. MISO, states, and its members have been working through these challenges through stakeholder and the Organization of MISO States (OMS) workshops on large load planning, long range transmission planning, and their expedited resource addition study (ERAS). ERAS is designed to move projects through the interconnection queue more quickly after state authorization to apply.

Coordinating and executing on the priorities within the Reliability Imperative is required to address challenges to reliability



MISO'S VALUE PROPOSITION

The value of a regional transmission organization (RTO) comes from the ability to share resources across the region. As resource mixes change and severe weather continues to increase, the value of sharing resources across

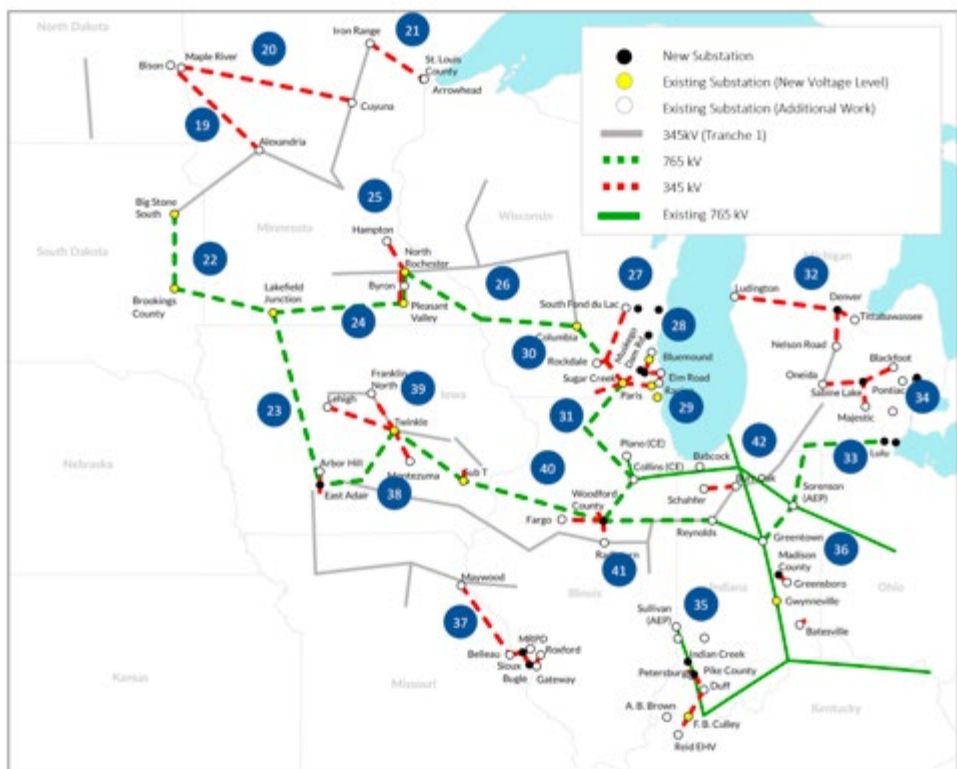
MISO is currently working with stakeholders to update its Value Proposition calculation for 2025 to better account for changing load growth, resource mix changes, operational risk, and transmission needs.

Included in MISO's Long Range Transmission Planning process, is MISO's Transmission Expansion Plan (MTEP). During the MTEP process, states and members work with MISO to address local and regional reliability needs. There are currently two long-term transmission plans in motion. Tranche 1 includes 18 projects across the MISO Midwest subregion estimated to cost \$10.3 billion. The Jetx project was one of the 18 projects in Tranche 1.



Tranche 2.1's portfolio focused on creating a 765 kV transmission "highway" within the MISO region to maximize value based on land use, line distances, transfer levels, and costs. Tranche 2.1 includes two 345 kV transmission line projects that reach North Dakota, the Maple River to Cuyuna transmission line and the Bison to Alexandria transmission line. The total cost of Tranche 2.1 is estimated to be \$21.9 billion with a benefit-to-cost ratio between 1.8 and 3.5. MISO is currently working with stakeholders to finalize "Futures" assumptions that will be used in the next planning phase.

Tranche 2.1 Identified a 24-project portfolio



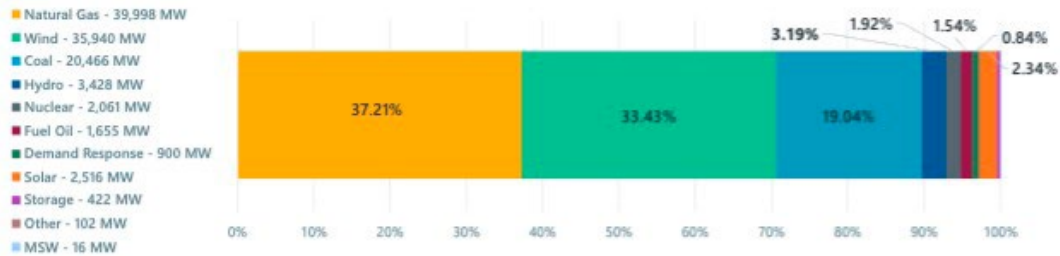
SOUTHWEST POWER POOL (SPP)

The Southwest Power Pool serves members in all or part of 14 states and provides additional energy services in 23 states and provinces. Its service territory covers 557,546 square miles and includes 5,292 substations and 72,884 miles of transmission lines. SPP has 63,908 MW of accredited generation capacity (accredited as of June 2024). SPP's coincident peak load of 56,184 MW occurred on July 31, 2023.

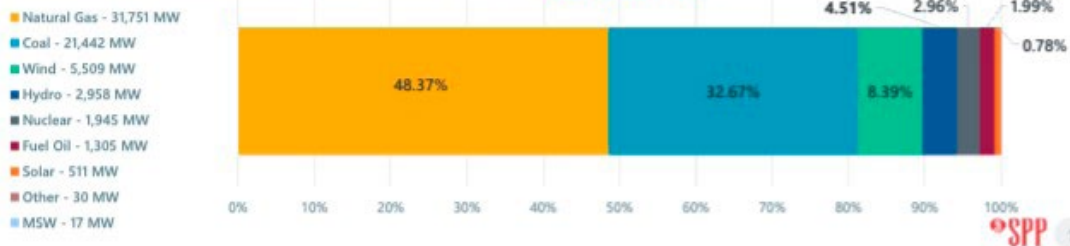
Over the past year, SPP has advanced a series of forward leaning initiatives that collectively enhance regional grid reliability, modernize transmission planning, and significantly accelerate the interconnection of new resources. These accomplishments reflect SPP's commitment to meeting growing load across the central United States—including in North Dakota—with policies and tools that shorten timelines, improve transparency, and support reliable, affordable service across the SPP footprint.



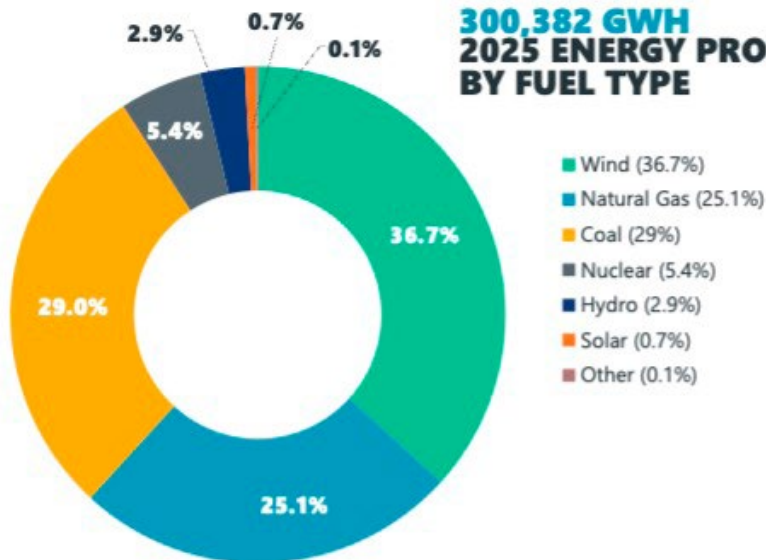
NAMEPLATE GENERATING CAPACITY – 107,502 MW (As of March 2026)



ACCREDITED GENERATING CAPACITY – 65,639 MW (As of Summer 2025)



300,382 GWH 2025 ENERGY PRODUCTION BY FUEL TYPE



SPP RESPONDING TO RAPID LOAD GROWTH AND NEW DEMANDS ON THE GRID

SPP continues to face historic load growth driven by economic expansion, evolving industrial demand, and the rapid development of data centers. SPP emphasized that projected load growth in some areas has increased dramatically, with expectations of sustained long term increases across the region.

To respond, SPP has prioritized accelerated planning processes and expanded transmission capability to ensure reliability during extreme weather and high demand periods. These efforts align with the reliability priorities of North Dakota utilities and policymakers, who have emphasized the need for sufficient accredited capacity and robust transmission to serve both existing customers and new large loads.

SPP INNOVATION IN TRANSMISSION PLANNING AND INTERCONNECTION

Over the last 12 to 18 months, SPP has delivered multiple industry leading reforms designed to improve “speed to power”: a priority for states anticipating major industrial development and electrification related growth.

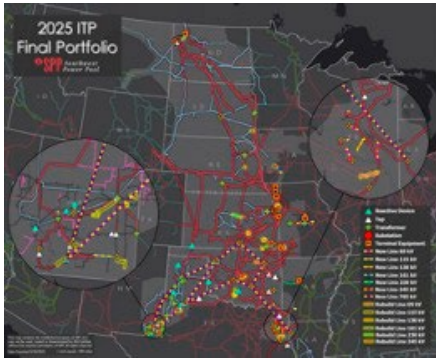
Key accomplishments include:

- **Expedited Resource Adequacy Study (ERAS) process**, now approved and affirmed by FERC, allowing load serving entities to more quickly interconnect generation needed specifically for resource adequacy. This has significantly reduced study timelines and supports regional reliability during periods of high load.
- **Surplus Plus provisions**, enabling entities to add generation at existing sites without undergoing the full generator interconnection (GI) process, further accelerating the delivery of new capacity.
- **High Impact Large Load (HILL) study process**, which allows certain large loads to be interconnected along with associated generation in 90 days or less when key criteria are met. This innovative framework is particularly valuable for regions experiencing large new industrial demand and offers a timely solution for economic development opportunities in North Dakota and the Upper Great Plains.
- **Conditional HILL process**, filed with FERC, which would allow load to be interconnected even more quickly on an interruptible basis: a pioneering approach to flexibility and speed.
- **Consolidated Planning Process (CPP)**, an integrated and forward looking planning framework expected to enhance certainty for developers by combining transmission planning and interconnection studies. Once approved, this approach will create more optimized and cost effective solutions across the footprint, directly benefiting states like North Dakota by reducing congestion and improving long term reliability.
- SPP continues to modernize its planning and operational tools, as through its partnership with **NVIDIA and Hitachi** to develop advanced planning technology, enabling more accurate modeling, faster analysis, and improved system planning.

Together, these reforms represent a bold restructuring of SPP’s planning and interconnection processes and set a national example for accelerated, coordinated infrastructure development.

SPP MAJOR TRANSMISSION INVESTMENTS AND LONG TERM GRID VISION

SPP's recent planning work includes significant progress on long range transmission development. Recent efforts have emphasized a coordinated backbone strategy designed to support substantial future load and facilitate reliable generation interconnection across the region.



- SPP has introduced a vision for a 765 kV extra high voltage backbone, which will support long-term reliability and load growth. Although still in early stages, this effort aligns with the needs of states experiencing increasing congestion and major anticipated load additions.



- The organization continues implementation of its 2025 Integrated Transmission Plan (ITP) portfolio: an ~\$8B portfolio of transmission projects that enhance regional reliability, reduces congestion, and supports resource adequacy and delivery point additions at a benefit-to-cost ratio of between 12-18:1. These projects complement new and ongoing transmission development in North Dakota—particularly in the western part of the state—where SPP's planning assessments have identified the need for additional 230 kV and 345 kV infrastructure.

Together, these investments improve the operational flexibility of the broader SPP system, which transmits power across more than 70,000 miles of transmission lines and includes thousands of substations across a highly interconnected region.

SPP STRENGTHENING RESOURCE ADEQUACY AND WINTER PREPAREDNESS

SPP has made notable progress enhancing regional resource adequacy, including significant improvements in resource accreditation. These steps have incentivized stronger performance across the generating fleet and contributed to reliable operations during recent severe winter events.

FERC has recognized SPP's leadership in accelerating interconnection timelines and advancing policies necessary to ensure continued reliability under growing demand. These acknowledgements underscore the regional value of SPP's reforms and support ongoing collaboration with state regulators, including North Dakota's PSC.

SPP REGIONAL BENEFITS FOR NORTH DAKOTA

North Dakota's participation in SPP provides important benefits for both reliability and economic opportunity:

- Faster interconnections support new load growth tied to agriculture, energy production, advanced manufacturing, and data center development: all priorities identified by North Dakota energy officials.
- Integrated regional planning helps address congestion in key areas serving the Bakken and other high-growth regions.
- Transmission investments across the Upper Great Plains enhance reliability in extreme weather and support the continued use of North Dakota's diverse generation resources, including dispatchable baseload.
- Policy leadership at SPP ensures that North Dakota's regulatory perspectives are incorporated into major regional planning decisions.

As load growth accelerates nationwide, North Dakota's position within SPP's service territory, supported by a rapidly evolving planning framework, will continue to provide significant value by enabling reliable service, supporting economic expansion, and improving connectivity across the broader regional grid.

NORTH DAKOTA GENERATION PROJECTS

Rainbow Energy: As of 2026, Rainbow Energy Center continues to advance a growth strategy centered on Coal Creek Station and the Nexus HVDC Line. The Rainbow Substation is complete and operational, enabling service to large on-site loads and supporting continued development at the site. Rainbow is evaluating options to expand capacity on the Nexus Line, along with diversified electricity generation expansion at the site to meet growing demand and enhance overall system reliability. Coal Creek Station continues to reliably serve 205 MW of interruptible on-site load through Adakon Energy. Rainbow Energy Center values its strong partnerships and remains committed to the reliable, efficient delivery of power in support of North Dakota's energy and economic goals.

NextEra: NextEra Energy Resources' subsidiaries have been fueling North Dakota's economic growth since 2003, while moving our country toward energy independence. NextEra Energy Resources plays a role in the state's energy future through operations at its various facilities, including 16 operational facilities with a combined 1,784.9 MW of operational capacity, in addition to two operational pipeline assets. The company has invested more than \$3.7 billion in energy infrastructure across the state with more than \$8.7 million paid in annual land payments and \$6.6 million paid in annual property taxes over the past two decades.

NextEra Energy Resources has multiple projects in various stages of development across the state, including renewable energy centers, battery energy storage systems, and transmission lines supporting various facilities. Additionally, NextEra Energy Resources and Basin Electric Power Cooperative (Basin Electric) have signed a memorandum of understanding to explore the joint development of a new combined-cycle natural gas-fueled generation facility in Basin Electric's North Dakota service territory. With a planned capacity of approximately 1,450 megawatts, the project, developed under Basin Electric's Large Load Commercial Program, would serve as the foundation for a multi-gigawatt data center campus. Basin Electric's Large Load Commercial Program is designed to reliably serve new, high-demand energy users while ensuring developmental and operational costs are covered by the large load that requires them.

WAPA – Upper Great Plains: WAPA-UGP markets and transmits federal hydropower from the region's Pick-Sloan Project dams. Operated by the U.S. Army Corps of Engineers, the Garrison Dam's five turbines, with a total installed capacity of 583 MW, produce around 2 million MWh annually. Garrison continues to receive unit maintenance and protective relay replacements on all units.

Basin Electric Power Cooperative: Basin Electric recently completed the addition of its fourth phase of natural gas generation at the Pioneer site. A total of 583 MW came online in 2025, consisting of six reciprocating engines and two combustion turbines.

Construction has also begun on the 1,470 MW Bison Station, a combined-cycle generating facility near Epping. The project is expected to be in service by 2030.

On the renewable energy front, Basin Electric is preparing to repower the Prairie Winds – North Dakota site near Max, ND. The eighty 1.5 MW wind turbines will be upgraded to units capable of 1.6 MW, increasing production and improving performance at lower wind speeds.

Otter Tail Power Company: Otter Tail Power's Abercrombie Solar is a 295-MW solar generation facility the company plans to build in Abercrombie Township northwest of Wahpeton, ND. In the second quarter of 2025, the Minnesota Public Utilities Commission and the South Dakota Public Utilities Commission approved cost recovery for Abercrombie Solar to serve customers in their respective states. The North Dakota Public Service Commission approved an Integrated Resource Plan action plan in 2024 that didn't include additional solar resources.

Once complete, Otter Tail Power estimates Abercrombie Solar will provide \$23.8 million in local and state tax benefits over the 35-year life of the facility and create approximately 300 construction jobs at peak construction.

Otter Tail Power is upgrading and refurbishing wind turbines at four of their owned wind energy centers. They repowered the Langdon Wind Energy Center in late 2024 and finished equipment upgrades at their Ashtabula, Ashtabula III, and Luverne Wind Energy Centers in Q1 2026. Otter Tail Power expects this wind repowering to

provide approximately 164 GWh of additional energy—the equivalent of a new 40-MW facility.

The company is also pursuing a new 200-300 MW wind facility in North Dakota to continue to meet the energy needs of its customers across the three states it serves.

Montana-Dakota Utilities Co.: The 250 MW Badger Wind project located near Wishek, ND, was placed in-service in December. MDU has a 49 percent ownership interest in the project.

Minnkota Power Cooperative maintains a diverse power supply portfolio with all generation resources located in North Dakota, including coal, wind and hydroelectric facilities. The cooperative continues evaluating its long-term resource strategy to ensure it can provide reliable, affordable and sustainable electricity for its members well into the future.

Progress continues on development of the Flickertail Wind Farm, a 370-megawatt (MW) project planned near New Rockford, ND. The wind facility will be owned and operated by PRC Wind, with Minnkota purchasing all of the energy produced through a long-term power purchase agreement. The project is expected to begin commercial operation in 2028.

Minnkota is also evaluating the potential addition of natural gas generation in North Dakota. Natural gas generation would provide flexible, dispatchable power that can complement other resources in the portfolio. The cooperative continues assessing potential technologies, locations, facility size and other considerations before making a final investment decision.

Great River Energy is advancing generation resources that complement its transmission investments. Great River Energy will purchase energy from a grid connected energy storage project that will be co-located with the Emmons–Logan wind farm and developed by NextEra Energy Resources, deploying 140 megawatts of four-hour battery storage with completion targeted by 2027. Great River Energy is also collaborating on other wind projects and evaluating potential North Dakota and Minnesota sites for future natural gas combustion turbine generation to provide firm, dispatchable capacity.

NORTH DAKOTA TRANSMISSION PROJECTS

Transmission line development is an exhaustive process, often taking 8 to 10 years from idea to operation. The load growth, particularly in Western ND, has been phenomenal but challenging for the power supplier and transmission developers. Today, there is significant transmission congestion in Southeast North Dakota. Fortunately, there are several transmission projects approved and well on their way to construction to alleviate the congestion and accommodate load growth, improve grid reliability and consumer security. The various utility projects are as follows:

RAINBOW ENERGY

Rainbow Energy owns the 436 mile High Voltage Direct Current (Nexus) line that originates at Coal Creek Station and terminates near Minneapolis, MN. The ND Industrial Commission, acting as the ND Transmission Authority provided bond financing for the purchase of the line from Great River Energy. Rainbow Energy is now evaluating options to expand capacity on the Nexus Line.

WESTERN AREA POWER ADMINISTRATION (WAPA)

WAPA's Upper Great Plains (UGP) transmission facilities are under the functional control of the Southwest Power Pool (SPP) Regional Transmission Organization and are included in the annual SPP transmission assessments. SPP's Integrated Transmission Planning (ITP) assessments identify a portfolio of transmission projects comprised of reliability, economic, short circuit, and operational projects intended to mitigate several system issues.

SPP's 2024 ITP portfolio included projects to address the rapid load growth in North Dakota. One of the major projects in the WAPA footprint is a new 439-mile, 345-kV line from Belfield to Maurine to New Underwood to Laramie River that brings large economic benefits to North Dakota and the SPP region. This project aims to address

the extra high-voltage deficiency in this area and benefit rural communities in western Nebraska and the Dakotas. Another major project for North Dakota is a new 230-kV line from Dawson County, Montana, to Williston, North Dakota, that would provide reliability and economic benefits and greatly reduced congestion on the area's 115-kV system.

SPP's 2025 ITP assessment identified a new 345-kV line from Belfield to Roundup that further builds upon the projects from the 2024 portfolio by relieving economic congestion in the area.

Other age and replacement projects identified by WAPA-UGP in the North Dakota area include a Fargo bus upgrade, Charlie Creek-to-Garrison transmission line rebuild, Jamestown reactor replacement, and Jamestown-to-Fargo 230-kV structure reroute. WAPA-UGP recently completed the Fargo bus upgrade with the remaining projects expected to be finished over the next one to two years. These projects will increase capacity, alleviate congestion, increase storm resilience, and provide for continued stability in their local areas.

Together, all these projects will increase transmission reliability in North Dakota, relieve economic congestion, ensure worker safety and line reliability, improve voltage control, and provide stability to the region.

MISSOURI RIVER ENERGY SERVICES

Missouri River Energy Services (MRES) provides supplemental wholesale power to 61 municipal electric utilities, six of which are located in North Dakota (Cavalier, Hillsboro, Lakota, Northwood, Riverdale, and Valley City). MRES also provides some services to its lone North Dakota associate member, Maddock. MRES is one of the utilities involved in the Bison, North Dakota to Alexandria Minnesota second circuit 345 kV transmission line project. This project will be constructed on mostly existing transmission line structures from the existing Bison Substation near Fargo, North Dakota to the existing Alexandria Substation in Alexandria, Minnesota. The existing 345 kV structures were previously permitted in North Dakota and Minnesota, and were constructed as double-circuit capable lines as a part of the CapX Fargo to St. Cloud 345 kV Transmission Project. This project will benefit the municipal electric utilities of North Dakota. MRES also actively participates in the transmission planning activities of both regional transmission organizations (MISO and SPP) covering North Dakota.

GRID UNITED – NORTH PLAINS CONNECTOR

Grid United's North Plains Connector (NPC) Project is a proposed approximately 420-mile, 525 kilovolt high voltage direct current (HVDC) project designed to bridge the Eastern and Western Interconnections between North Dakota and Montana. The project has been in development since 2021 and continues to make substantive progress towards meeting its estimated in-service date of 2032. The line is expected to have an initial capacity of 3,000 MW and will connect three electric transmission regions: the Western Interconnection, the Midcontinent Independent System Operator (MISO) and the Southwest Power Pool (SPP).

As of December 2025, NPC has voluntarily acquired access for over 95% of the project's right of way, including over 98% acquisition in North Dakota. NPC is a merchant development but has secured commitments from utilities across the project's footprint including Montana-Dakota Utilities and Allete with operations in North Dakota. The project is on track to have permitting substantially completed by the end of 2026 and will begin construction in 2028.



CENTRAL POWER COOPERATIVE (CPEC)

Long Term Investments Completed in 2025

- **Apple Creek Distribution Substation – South Bay Addition** – CPEC completed construction of an additional 43.8-13.2kV, 14 MVA distribution substation bay within the existing Apple Creek substation to provide capacity and redundancy in the vicinity of Lincoln, ND. The transmission line serving the substation was modified as part of the project and new motor operated devices were added to the substation tap switches.
- **Kensal Distribution Substation Replacement** – The original Kensal substation was built in 1973 and the structures were compact with tight clearances between substation components. The replacement Kensal distribution substation was built roughly 2 miles northeast of the original substation and was loaded in late December.
- **Kensal to Glenfield 43.8kV Transmission Line Project** – The new 16-mile transmission line was constructed to provide looped service to Central Power’s Glenfield and new Kensal distribution substations. This line, combined with the new Kensal Tap to Kensal 43.8kV transmission line which is described directly below, will eventually allow the existing 18.4-mile Brantford Tap to Glenfield line, built in 1959, to be taken out of service long enough to permit a total line rebuild.
- **Kensal Tap to Kensal 43.8kV Transmission Line Project** – The new 13.5-mile transmission line is nearly complete with one remaining 3,000’ crossing over the Arrowwood National Wildlife Refuge remaining. CPEC has all required permits and our line contractor plans to complete the crossing in early 2026.
- **New Rockford Distribution Substation Replacement** – The Central Power New Rockford distribution substation was built in 1950 and the structures were a compact design with very tight clearances between substation components. Central Power completed construction of a larger modern replacement for the New Rockford distribution substation south of the existing substation but it has not been energized after delays associated with underground railroad crossings. CPEC anticipates completing the project in late spring 2026.
- **Wahpeton ProGold Substation Control System Replacement** – The ProGold control and protection system was replaced as part of a planned equipment replacement rotation. The project involved designing, building, programming, and replacing the existing control and protection system with modern microprocessor-based relays and control equipment.

- **Ward 230kV Substation Control System Replacement** – The control and protection system for Central Power’s part of the substation, which is jointly owned with WAPA, was replaced as part of a planned equipment replacement rotation. The project involved designing, building, programming, and replacing the existing control and protection system for the 115kV and 43.8kV portions of the substation with modern microprocessor-based relays and control equipment.

CPEC Projects for 2026

- **Benedict Breaker Station - Breaker 15 Replacement** – Benedict breaker 15 is at the end of its useful life and will be replaced with a modern SF6 breaker.
- **Bismarck East Substation Control System Replacement** – The Bismarck East distribution substation protection system was installed in 2003 and has reached the end of its useful life. The project will involve replacing four protective relays and the substation Programmable Logic controller (PLC) with modern versions.
- **Bismarck North Circuit Switcher 362 & 462 Replacement** – These two fault clearing devices are at the end of their useful life and will be replaced with new 115kV SF6 power circuit breakers.
- **Blue Flint Distribution Substation – South Bay Addition** – We will add a 43.8-13.2kV, 14 MVA distribution substation bay within the existing Blue Flint substation to provide capacity and redundancy for the Blue Flint Ethanol Plant.
- **Crooked Lake to Lincoln Valley 43.8kV Transmission Line Construction** – The new 22 mile 43.8kV transmission line, once completed, will provide looped transmission service to Central Power’s Crooked Lake and Lincoln Valley substations. This new line will also eventually allow the existing 15-mile-long Crooked lake line and the 21-mile-long Lincoln Valley line, which were built in 1963 and 1966 respectively, to be taken out of service long enough to permit total rebuilds.
- **Dunning 115kV Substation Equipment Replacement** – The Dunning 115-43.8kV transformer along with four 43.8kV breakers and the 43.8kV potential transformers are reaching the end of their useful life. CPEC plans to install a new larger 115-43.8kV transformer, to replace the four breakers along with their disconnect switches, to replace the potential transformers, and to replace the 43.8kV bus.
- **Mallard 115kV Substation Capacity Related Transformer Replacement** – Central Power ordered a larger transformer for its initial Phase 1 Mallard rebuild project that occurred in 2023 but that transformer was delivered to the Carrington 115kV substation after the Carrington transformer failed. CPEC now plans to replace the smaller 1993 transformer at Mallard with a new larger unit and will relocate the existing Mallard transformer, which still has a significant life expectancy and value, to the Gibbs 115kV substation. The existing Gibbs 115-43.8kV transformer is a rather small and portable unit which will then be moved to a Central Power transformer nursery where it will be stored energized until it is needed somewhere.
- **Menoken Distribution Substation Rebuild** – The Menoken distribution substation structures are a compact design with very tight clearances between substation components, the substation is contained in a very compact fenced area, and Capital Electric Cooperative requested additional distribution circuit exits which cannot be accommodated within the existing footprint. Central Power will build a modern substation with an expanded low side structure on the existing site.
- **Millarton Distribution Substation Construction** – Central Power will build a new 115-12.5kV distribution substation to replace the existing Millarton substation. The new substation will be served from a tap on WAPA’s Jamestown to Edgeley transmission line.
- **Neal 115kV Substation Equipment Replacement** – The Neal 115-43.8kV transformer along with four 43.8kV breakers and the 43.8kV potential transformers are reaching the end of their useful life. CPEC plans to install a new larger 115-43.8kV transformer on a new pad within the Neal substation and to replace the four breakers along with the potential transformers in their existing locations. Power transformer vendors within the U.S. are still experiencing four-year lead times and Central Power determined that it would be advantageous to leave the existing transformer in place, as an energized spare unit, after disconnecting the low side connections. CPEC will then be in a position to relocate the older unit as a temporary replacement should we experience a 115-43.8kV transformer failure within any of our substations.
- **Rolla to Rock Lake 43.8kV Transmission Line Rebuild** – The 16.2 mile 43.8kV transmission line between Central Power’s Rolla 115kV substation and Central Power’s Rock Lake distribution substation along with the 2-mile tie line between Central Power’s Rock Lake Tap and Otter Tail Power’s Rock Lake line were built in 1967. These lines are of unshielded construction and are reaching the end of their useful life with a history of broken

insulators. CPEC plans to build complete replacements in or near their existing locations.

- **Ruthville 115kV Substation Control System Replacement** – The Ruthville substation control and protection system will be replaced as part of a planned equipment replacement rotation. The project will involve designing, building, programming, and replacing the existing control and protection system using modern microprocessor-based relays and control equipment.
- **Woodworth to Robinson to Tuttle 43.8kV Transmission Line Rebuild** – The 20 mile 43.8kV transmission line between Central Power's Woodworth and Robinson substations was built in 1972 while the 12 mile 43.8kV transmission line between Central Power's Robinson and Tuttle substations was built in 1978. These lines are unshielded with a history of galloping and broken insulators. CPEC plans to build complete replacements in or near their existing locations.
- **Wyndmere North Distribution Substation Rebuild** – The Wyndmere North distribution substation structures are a compact design with very tight clearances between substation components, the substation is contained in a very compact fenced area, and Dakota Valley Electric Cooperative is planning to replace the distribution circuits leaving the substation. Central Power will build a modern substation directly adjacent to the existing site.

BASIN ELECTRIC POWER COOPERATIVE

Basin's current transmission activity includes the following projects:

- Leland Olds – Crane Creek – Tande 345 kV (161 miles) – 2026
- Wheelock – SK Border 230 kV (53 miles) – 2027
- Tande – SK Border 230 kV (59 miles) – 2027
- Patent Gate – Pioneer (50 miles) – 2029
- Leland Olds – Logan – Crane Creek 345 kV (130 miles) – 2032

In addition to those active projects, SPP's Board of Directors approved the 2025 ITP portfolio in November 2025 and approved the modification of projects from the 2024 ITP in February 2026 to be Basin's responsibility. Basin is currently developing cost estimates for these projects and has not yet taken them to their Board for approval. These projects include:

- Laramie River Station - Rapid City 345 kV (~240 miles)
- Rapid City - Belfield 345 kV (~235 miles)
- Belfield – Roundup 345 kV (~60 miles)
- Dawson County – Judson 230 kV (100 miles)
- Marley area 345/115 kV substation

OTTER TAIL POWER COMPANY

Otter Tail Power Company is currently working on several major transmission grid enhancement projects in North Dakota to enhance reliability, increase resiliency to extreme weather events, reduce congestion, and expand access to low-cost electricity. These projects include:

Jamestown – Ellendale 345-kV Transmission Line

In partnership with Montana-Dakota Utilities, Co., Otter Tail Power is developing a new approximately 92-mile, 345-kV transmission line from Jamestown, ND, to Ellendale, ND. Both ends of the line will have expanded substations to support the double-circuit capable line, with the company expanding the Jamestown substation. In addition, Otter Tail Power will be replacing the 345- and 230-kV transformers at the Maple River 345-kV Substation near Fargo, ND, as an underlying upgrade.

Maple River – Cuyuna 345-kV Transmission Line

Otter Tail Power is collaborating with Great River Energy (GRE) and Minnesota Power (MP) to develop the Maple River–Cuyuna transmission line, which includes construction of a new approximately 160-mile, 345-kV transmission line. The line will connect Otter Tail Power's Maple River Substation near Fargo, ND, to MP's Cuyuna substation near Riverton, MN. The Project is to be constructed with double-circuit capable structures, though initially operated as a

single transmission line. The North Dakota portion of the project consists of approximately six to ten miles of new 345-kV transmission line extending from Otter Tail Power's existing Maple River Substation to the North Dakota/Minnesota border, with much of the project located in Minnesota.

Forman – Hankinson 230-kV Rebuild

Otter Tail Power is also undertaking a project to rebuild the existing 37-mile, 230-kV line between the Forman Substation near Forman, ND, and the Hankinson Substation, near Hankinson, ND.

Fargo – Alexandria 345-kV Transmission Line

Xcel Energy, in partnership with Otter Tail Power, Great River Energy, Minnesota Power, and Missouri River Energy Services is adding a second 345-kV circuit along the existing 135-mile transmission line from Xcel Energy's Bison Substation near Fargo, ND, to their Alexandria Substation in Alexandria, MN.

Big Stone South – Hankinson – Bison 345-kV Transmission Line

As part of the Joint Targeted Interconnection Queue study completed by MISO and the Southwest Power Pool (SPP), Otter Tail Power and Xcel Energy are moving forward with the development of a new approximately 75-mile, single-circuit 345-kV line from Otter Tail Power's Hankinson Substation near Hankinson, ND, to Xcel's Bison Substation near Mapleton, ND. Otter Tail Power will continue the new single circuit 345-kV line from Hankinson, ND, to its Big Stone South Substation near Big Stone City, SD, a distance of approximately 75 miles.

Big Stone South to Hankinson to Bison will provide reliable connections and reduce congestion along the boundaries between the MISO and SPP grids.

The project will be partially funded through U.S. Department of Energy grants, helping lower long term costs for customers. The remaining costs are expected to be covered by long term contracts, meaning the generators that benefit from the project will help pay for it. Improvements are also planned at both endpoint substations with the most significant improvement involving the construction of a new 345-kV switchyard at Otter Tail Power's Hankinson Substation.

Beyond these major transmission projects, Otter Tail Power is evaluating several local 230-kV and 115-kV transmission projects to help alleviate local and regional transmission congestion and enhance reliability. And to address concerns with aging infrastructure, Otter Tail Power is performing several transmission line upgrades across its system, some of which are located in North Dakota. For example, 41.6-kV transmission line upgrades are currently underway between Buffalo and Colgate, as well as between Rugby and Bottineau, along with numerous overhead-to-underground distribution projects.

Otter Tail Power is the middle of its **Next-Generation Grid Resiliency Plan**, a grant-funded program focused on improving system reliability. The plan increases transmission and distribution pole inspections by 63% and includes expanded vegetation management across North Dakota. Guided by the Intelligent Vegetation Management System, 26 distribution feeders (approximately 95 miles) were fully trimmed in 2025, with plans in 2026 to address 65 overhead feeders totaling about 350 miles.

Improving reliability includes decreasing risks associated with natural events like storms and wildfires. In 2025 Otter Tail Power completed a Wildfire Mitigation Plan to address landscape and environmental risks associated with wildfires. This plan includes identification and assessment of areas in their system that may be prone to wildfires, use of internal and external sources to evaluate and mitigate risks, programs to reduce wildfire hazards, work practices aimed at mitigating identified risks, enhancement of protocols for effective mitigation, employee training on wildfire safety and operational responsibilities, and engagement with community members and stakeholders in wildfire mitigation efforts.

XCEL ENERGY

Xcel Energy is working to develop several regional transmission projects that will help deliver continued reliability to customers throughout the region to meet future expected electric growth.

Key projects completed:

- Brookings County-Twin Cities 2nd Circuit (adding a 2nd circuit to the open position on portions of the 345 kV

transmission line between Brookings, SD and Hampton, MN).

Future regional projects—MISO Tranche 2.1

- Fargo-Alexandria 2nd Circuit (MISO LRTP 19). This MISO Tranche 2.1 project will add a second circuit to existing transmission infrastructure between the Bison Substation near Fargo and the Alexandria Substation in Alexandria, MN. A Certificate of Need was filed in January 2026 in Minnesota and expect to file regulatory applications in North Dakota in Q1 2026.
- Fargo Area Upgrades. This MISO Tranche 2.1 project will rebuild aging infrastructure in the Fargo area to increase transmission line ratings and increase capacity in the growing Fargo area. The rebuilt 230 kV transmission lines will improve reliability and enable continued electric and economic growth in the Fargo area.
- PowerOn Midwest (MISO LRTP 22, 23, 24, 25). This MISO Tranche 2.1 project extends from the Big Stone South Substation and connects to the Brookings County substation (Brookings, SD), Lakefield Junction Substation (Jackson County, MN), Pleasant Valley Substation (Mower County, MN), North Rochester Substation (Goodhue/Olmstead Counties, MN), and includes two 345 kV segments in Dodge, Olmstead and Dakota Counties in Minnesota). The Minnesota Certificate of Need was filed in February 2026; the South Dakota Facility Permit will be filed in September 2026.
- Gopher to Badger Link (MISO LRTP 26). This MISO Tranche 2.1 project extends from the North Rochester Substation to the Mississippi River (and into Wisconsin). Xcel Energy and Dairyland Power Cooperative filed an application for a Certificate of Need in February 2026 and are developing route options, including hosting open houses asking for feedback on preliminary options. We expect to file a Route Permit application in Fall 2026.

Joint Transmission Interconnection Queue

- Bison-Hankinson-Big Stone (North Dakota and South Dakota). This 345 kV project, along with others in the region, will connect the MISO and SPP systems, increasing generation capacity and help ensure reliability due to increased access to energy resources. Regulatory applications are expected to be filed in 2026.
- Lyon County-Lakefield Junction (Minnesota). This 345 kV project will also connect MISO and SPP systems, increasing generating capacity and help ensure reliability due to increased access to energy resources. Regulatory applications are expected to be filed in 2027.

Buffalo Ridge Rightsizing

- Xcel Energy is developing a new 345 kV project that will connect the Pipestone and Chanarmbie Substations in Southwest Minnesota with the Renner and Split Rock Substations in South Dakota.

MONTANA DAKOTA UTILITIES (MDU)

Montana-Dakota Utilities Co. (MDU) completed several projects in 2025. Wishek Substation, completed in October, was rebuilt based on age and condition and to accommodate the Badger Wind interconnection. Substation and transmission work was completed at Ellendale for new data centers. An addition was placed in-service at MDU's Tioga 230 kV Substation to retire existing facilities due to age and condition.

MDU also has several projects in development or under construction. MDU continues its partnership with Otter Tail Power Company in the Jamestown to Ellendale (JETx) 345kV transmission project. Both ends of the line will have expanded substations, with MDU expanding the Ellendale Substation. The JETx project is expected to be completed in early 2029. A new Stanley Substation is being constructed to replace the existing substation. This project will improve reliability in the Stanley area and is scheduled for completion in 2026. Construction will begin in the summer of 2026 on the Lignite to Kincaid 60 kV transmission line. This new transmission line will eliminate the need for the Kincaid Substation, which will be retired. Development activities continue for the Hettinger to Elgin transmission line upgrade project. This project will convert the existing 69kV line to 115kV. The scheduled in-service date is 2028. The Merricourt project will also continue throughout 2026 with an expansion of the Merricourt Substation to support MDU's existing 42 kV system in the area. This project includes constructing two new 42 kV transmission lines from Merricourt to the Fredonia area and the Ashley area. These system upgrades will improve load serving capability and improve reliability. Scheduled in-service dates are 2028.

MINNKOTA POWER COOPERATIVE

Minnkota Power Cooperative continues to advance several power delivery infrastructure projects and operational

improvements across North Dakota. The cooperative currently operates and maintains 265 substations and approximately 3,890 miles of transmission line.

In 2025, Minnkota responded to some of the most severe summer storm damage in its history. Major storm systems in June and August caused significant damage to portions of the transmission system, requiring extensive repair efforts.

Minnkota operates two 345-kilovolt (kV) transmission lines stretching more than 364 miles, carrying power from western North Dakota generation resources to load centers in eastern North Dakota. In 2025, crews replaced 13 transmission structures and completed other improvements along this corridor, helping extend the life of this critical high-voltage infrastructure.

The cooperative also continued its programmatic reliability improvement efforts. This work included a complete rebuild of 35 miles of 69-kV transmission line in eastern North Dakota. Distribution substation improvements also moved forward, with full rebuilds completed at the Cominco and Leal substations in North Dakota. Together, these projects reduce outage risk and improve system performance.

Minnkota also completed significant system modifications related to the Fargo-Moorhead Flood Diversion Project. The Oxbow 69-kV substation was relocated and rebuilt outside the floodplain to protect critical infrastructure. In addition, eight transmission line crossings were modified to span the diversion channel, ensuring system integrity as the region's landscape evolves.

Near Harwood, Minnkota is also preparing to serve a large data center currently under development. In 2026, the cooperative plans to construct approximately 1.75 miles of 345-kV transmission line and a new 345-kV substation to support the load. In addition to serving the data center, this infrastructure will create opportunities for long-term growth in the region north of Fargo. All project costs will be fully funded by the data center developer.

MINNESOTA POWER – ALLETE

Minnesota Power/ALLETE will begin construction of its HVDC Modernization Project at their HVDC terminal near Center, ND in 2027. The project will increase capacity of the existing corridor from 550MW to 900MW with potential to increase to 1,500MW along with bringing new flexibility and reliability attributes to the North Dakota grid. The project work occurs at either end of the HVDC line at the converter stations. The project will begin in Spring of 2027 and will be completed in 2029.



The new voltage source converter station will look like the above when completed.

Minnesota Power is collaborating with Otter Tail Power (OTP) and Great River Energy (GRE) to develop the Maple River–Cuyuna transmission line, which includes construction of a new approximately 160 to 180-mile, 345-kV transmission line. The line will connect OTP's Maple River Substation near Fargo, ND, to MP's Cuyuna substation

near Riverton, MN. The Project is to be constructed with double-circuit capable structures, though initially operated as a single transmission line. The North Dakota portion of the project consists of approximately six to ten miles of new 345-kV transmission line extending from OTP’s existing Maple River Substation to the North Dakota/Minnesota border, with much of the project located in Minnesota.

GREAT RIVER ENERGY

Great River Energy’s transmission system is part of a coordinated regional grid serving the Upper Midwest. Great River Energy owns and operates more than 5,100 miles of transmission lines and over 100 substations and supplements its system through contractual access to other utilities’ facilities across six MISO pricing zones. To maintain reliability, Great River Energy makes substantial annual investments in maintenance, replacement and upgrades, with a strong emphasis on system resilience. Using lessons learned from major storms and a future weather risk study, Great River Energy prioritizes rebuild projects as part of our asset renewal plan and targets rebuilding 50 to 80 miles of transmission line infrastructure each year.

Beyond its local system, Great River Energy is actively collaborating on regional transmission solutions to support new generation, meet growing electricity demand and improve resilience amid more frequent extreme weather. In December 2024, the MISO Board approved Tranche 2.1 of the Long Range Transmission Plan (LRTP). Great River Energy is participating in two North Dakota–related projects: the Maple River to Cuyuna 345-kV transmission line project and the Fargo to Alexandria second-circuit 345-kV transmission line project. Certificate of need applications for both projects were filed with the Minnesota Public Utilities Commission in January 2026, with North Dakota regulatory applications expected in the second half of 2026. GRE is co-developing these projects with several regional utilities. Public engagement began in 2025 with additional outreach planned in 2026.

Great River Energy is also pursuing strategies to maximize the capacity of existing transmission infrastructure. A pilot project with Heimdall Power deployed dynamic line rating sensors that collect real-time environmental and line data to increase usable transmission capacity. After 12 months of operation, the project demonstrated up to 63% additional capacity during peak demand and an estimated \$3 million in avoided congestion costs over five years. Great River Energy has also launched a multi-year monitoring pilot with Prisma Photonics across approximately 90 miles of transmission lines, providing real-time alerts for grid events such as faults, physical disturbances and severe weather, improving situational awareness and response efficiency.

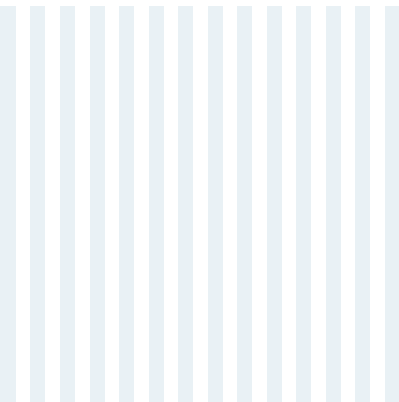
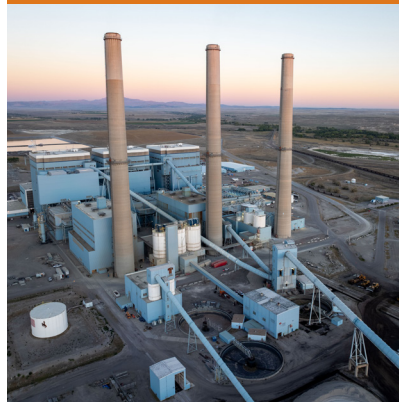
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DISCLAIMER

This report utilizes data from various sources. Those sources are appreciated for their willingness and availability. If users of this report utilize that information, please go to the source to assure the most accurate and up to date information.

Thanks for the Energy Information Administration (EIA), Southwest Power Pool (SPP), Midcontinent Independent System Operator (MISO), area utilities and WIND and their members especially.

SUMMER 2026



RESILIENCE OF THE ELECTRIC GRID IN NORTH DAKOTA

NORTH DAKOTA
TRANSMISSION AUTHORITY

The North American Electric Reliability Corporation (NERC) produces a seasonal grid reliability assessment for winter and summer seasons. This reliability assessment covers the United States and Canada.

Similarly, the **Midwest Reliability Organization (MRO)** produces a seasonal grid reliability assessment for the Midwest region, covering the central states from northern Texas to Canada, including Saskatchewan and Manitoba. This region includes North Dakota. The MRO's Summer 2026 Reliability Assessment was released June 3, 2026. The full report is included in this document.

As part of Midwest Reliability Organization's annual summer assessment, staff engineers determined that operating reserves are expected to remain sufficient under normal summer weather conditions, assuming typical maintenance schedules and planned generation outages across the region.

However, periods of extreme heat that drive demand spikes, combined with forced generation outages, could result in insufficient electricity supply in SaskPower's service area. In those circumstances, SaskPower may need to implement demand response programs, arrange short-term power transfers, or issue energy emergency alerts to maintain required operating reserve levels.

This summer's outlook represents an improvement compared with previous years, reflecting the efforts of utilities across the region to add approximately 10 GW of new generation capacity, mostly from solar and hydro resources.

MRO's 2026 Regional Summer Assessment provides key stakeholders with critical insights into potential reliability challenges and recommends actions to mitigate risks. The report also highlights bulk power system performance trends specific to the MRO region to inform long-term system planning.

North Dakota generation and transmission owners & developers continue to build out transmission and generation assets. Both cooperative generation and transmission entities and investor-owned utilities see opportunities to develop natural gas generation in North Dakota to meet capacity requirements (dispatchable generation) and recognize that North Dakota also has rich wind resources that can be appropriately leveraged to meet energy requirements. Fortunately, the coal industry has received regulation reprieve, allowing coal generation facilities to plan for a more robust future. Solar projects offer valuable capacity attributes for summer peaks, with peak production aligning with summer peak consumption. Hydropower, though a small segment of the generation mix, is a dependable and flexible generation asset. Nuclear energy holds promise, particularly in the small modular reactor realm; however, like coal, the development and construction of a facility requires several years.

A handwritten signature in black ink, appearing to read "Claire Vigesaa". The signature is fluid and cursive, with a large initial 'C'.

Claire Vigesaa, Executive Director
North Dakota Transmission Authority

Table of Contents

Preface	4
About the Organizaton	4
Executive Summary	5
Key Findings	5
Summer Season Trends	5
Recommendations	6
Chapter 1: Assessment Overview	7
Process	7
Area Studied	7
Chapter 2: 2026 Summer Outlook.....	9
By Assessment Area	9
Manitoba Hydro	9
Midcontinent Independent System Operator	9
Saskatchewan Power Corporation	10
Southwest Power Pool	10
Chapter 3: Historical Seasonal Trends	11
Bulk Electric System Event Analysis	11
Transmission System Events	11
Energy Management System Events	12
Energy Emergency Alerts	13
Generating Availability	13
Transmission Availability	14
Protection System Misoperations	15
Historical Summer Load Forecast	19
Chapter 4: Emerging Risks	21
Large Load Growth	21
Generation Resource Mix	21
Wind	22
Solar	22



Summary of Risk	22
Chapter 5: Summary	23
Focus Areas for 2026 Summer	23
Appendix A: Registration and Certification	24
Registration	24
Certification	25
Appendix B: Summer Seasonal Forecast	26
Anticipated Summer Resource and Peak Demand Scenario	26
Wind and Solar Resources	30
Appendix C: BES Event and EEA Details	32
Appendix D: Generating Availability Details	34
Appendix E: Transmission Availability Details	39
Glossary	42



Preface

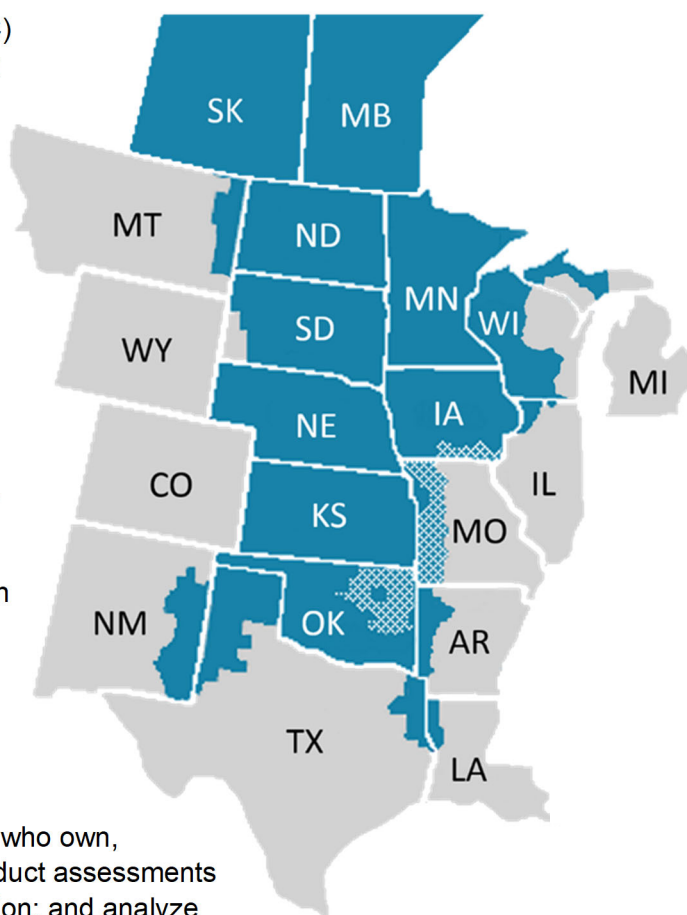
ABOUT THE ORGANIZATION

Midwest Reliability Organization (MRO) is dedicated to its vision of **a highly reliable and secure North American bulk power system**. To ensure reliability of the bulk power system in the United States, Congress passed the Energy Policy Act of 2005, creating a new regulatory organization called the Electric Reliability Organization (ERO) to establish mandatory Reliability Standards and monitor and enforce compliance with those standards on those who own, operate or use the interconnected power grid.

In 2006, the Federal Energy Regulatory Commission (FERC) approved the North American Electric Reliability Corporation (NERC) as the ERO under section 215(e)(4) of the Federal Power Act. NERC delegates its authority to monitor and enforce compliance to six Regional Entities established across North America, of which MRO is one. Recognizing the international nature of the grid, NERC as the ERO, along with MRO, established similar arrangements with provincial authorities in Canada.

The MRO region spans the provinces of Saskatchewan and Manitoba, and all or parts of the states of Arkansas, Illinois, Iowa, Kansas, Louisiana, Michigan, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wisconsin. The region includes more than 290 organizations that are involved in the production and delivery of electric power, including Canadian utilities, cooperative and municipal utilities, investor-owned utilities, along with federal power marketing agencies, generator power marketers, and transmission system operators.

MRO's primary responsibilities are to monitor and enforce compliance with mandatory Reliability Standards by entities who own, operate, or use the North American bulk power system; conduct assessments of the grid's ability to meet electric power demand in the region; and analyze regional system events. Additionally, MRO creates an open forum for stakeholder experts and provides outreach across the region to discuss important topics related to addressing risk and improving reliable operations of the bulk power system.



Executive Summary

This annual assessment provides information and raises awareness of regional bulk power system challenges and trends, helping industry stakeholders and decision-makers reduce risk and maintain electric reliability during the summer season. The 2026 Regional Summer Assessment (RSA) provides critical insights for the upcoming summer season, specifically the months of June through September. In developing the 2026 RSA, MRO staff analyzed data from the four Planning Coordinators (PCs) operating in the region to determine if adequate electricity generation and transmission is available to meet projected peak summer demand. The four PCs in MRO's region are: Manitoba Hydro, Midcontinent Independent System Operator, SaskPower Corporation, and Southwest Power Pool.

Additionally, this report incorporates quarterly data from over 290 registered entities (users, owners, and operators of the bulk power system) to assess the regional grid's performance during previous summer seasons. This helps identify key trends and emerging risks. Information on the identification, registration, and certification of these entities is available in [Appendix A](#).

This report complements NERC's North American Summer Reliability Assessment by providing a more detailed analysis of reliability concerns specific to MRO's geographic area.

KEY FINDINGS

- Anticipated resources are sufficient to meet operating reserve requirements under normal peak demand conditions with typical maintenance and forced outages in all PC areas.
- Sufficient resources are also anticipated to meet operating reserve requirements under extreme peak demand, even when coupled with extreme weather conditions, in the Manitoba Hydro, Midcontinent Independent System Operator, and Southwest Power Pool areas.
- Although SaskPower Corporation anticipates sufficient capacity and reserve margin to meet peak summer demand, there is an elevated risk of insufficient energy to serve load at all hours, according to the probabilistic energy analysis.
- Midcontinent Independent System Operator experienced a large increase in resource availability compared to the 2025 summer season, with a new record set for nameplate installations¹ in 2025.
- Capacity margins continue to tighten for Southwest Power Pool due to increasing load growth and a changing resource mix.
- Interruptions to fuel supply, combined with the growing share of variable energy resources, could create unique operational challenges. As variable resources become a larger part of the region's energy mix, their performance during periods of high demand becomes increasingly critical.

SUMMER SEASON TRENDS

- Eleven Bulk Electric System (BES) transmission events occurred on the regional system in 2025 - the lowest number since MRO began performing seasonal assessments.
- Summer generator performance improved compared to the previous year; however, ongoing outages from the spring maintenance cycle—particularly among fossil steam and simple cycle

¹ Nameplate capacity is the maximum sustained power output a generator or power plant can produce under ideal, manufacturer-specified conditions



units—led to higher event impacts and increased Weighted Equivalent Forced Outage Rate (WEFOR) percentages.

- The number of unknown momentary transmission line outages decreased by 53% compared to 2024, marking significant improvement following the 66% increase observed in 2024 relative to 2023.
- While total protection system misoperations increased by approximately 5% from 2024, the 2025 misoperations rate was well below the five-year average.

RECOMMENDATIONS

The following actions are recommended to mitigate risks of energy shortfalls on the regional bulk power system this summer:

- Reliability Coordinators (RCs), Balancing Authorities (BAs), Transmission Operators (TOPs), and Generator Operators (GOPs) should maintain heightened situational awareness during periods of unplanned generation or transmission outages, extreme weather conditions, and low wind forecasts.
- These organizations should also implement operating procedures as needed to ensure resource adequacy.
- RCs, BAs, and Generator Owners (GOs) should develop protocols to ensure sufficient generation resource availability before the summer season.
- State and provincial regulators should be prepared to support grid operators by approving environmental and transportation waivers and the issuance of public appeals to conserve electricity, both before and during the summer season.



Chapter 1: Assessment Overview

PROCESS

As part of the ERO Enterprise (collectively NERC and the Regional Entities) reliability assessment process, MRO staff independently evaluate and report on regional electricity supply and demand, transmission system adequacy, and emerging trends that could affect bulk power system stability.

This work is mandated by [MRO's Regional Delegation Agreement](#), Section 800 of the [NERC Rules of Procedure](#), and the [ERO Enterprise Reliability Assessment Process](#).

The data MRO assesses each year is collected from regional RCs and PCs. The PCs are responsible for integrating transmission facilities, service plans, resource plans, and protection systems in their analyses to ensure reliable power within their specific footprints. These organizations collaborate with Transmission Planners (TPs) to assess the reliability impact of resource and transmission outages within interconnected areas. The RCs are responsible for the real-time reliable operation of the bulk power system and have a wide-area view of system operations. They hold the highest level of operational authority within their designated footprints.

In addition to the four PCs in MRO's region, there are three RCs: Midcontinent Independent System Operator (who also serves as the RC for Manitoba Hydro), SaskPower Corporation, and Southwest Power Pool.

NERC's [2026 Summer Reliability Assessment](#) covers all of North America and is a coordinated evaluation between the NERC [Reliability Assessment Subcommittee](#), NERC staff, and the six Regional Entities.² While MRO's RSA leverages some of the same data, historical information is also studied to offer a targeted, regional view of reliability concerns, trends, and emerging risks.

AREA STUDIED

MRO's region includes two Canadian provinces and all or parts of 16 U.S. states. Notably, the Midcontinent Independent System Operator footprint spans three Regional Entities: MRO, ReliabilityFirst (RF), and SERC Reliability Corporation (SERC). MRO is responsible for collecting resource and transmission system adequacy data for the entire Midcontinent Independent System Operator area and coordinates with RF and SERC for review and preparation of NERC reliability assessments. However, MRO's review of Midcontinent Independent System Operator's historical performance data is limited to the MRO region. Additionally, MRO gathers and analyzes performance data and NERC reliability assessment information for the entire Manitoba Hydro, SaskPower Corporation, and Southwest Power Pool footprints.

The sources used for this assessment include NERC's 2026 Summer Reliability Assessment and MRO's [Performance Analysis](#) data used in NERC's Generating Availability Data System (GADS), Transmission Availability Data System (TADS), Misoperation Information Data Analysis System (MIDAS), and Event Analysis (EA).

Figure 1.1 illustrates the North American assessment areas, and Figure 1.2 shows the boundaries of the North American Regional Entities, which do not align precisely with the assessment areas.

² <https://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx>





Figure 1.1: NERC Assessment Areas

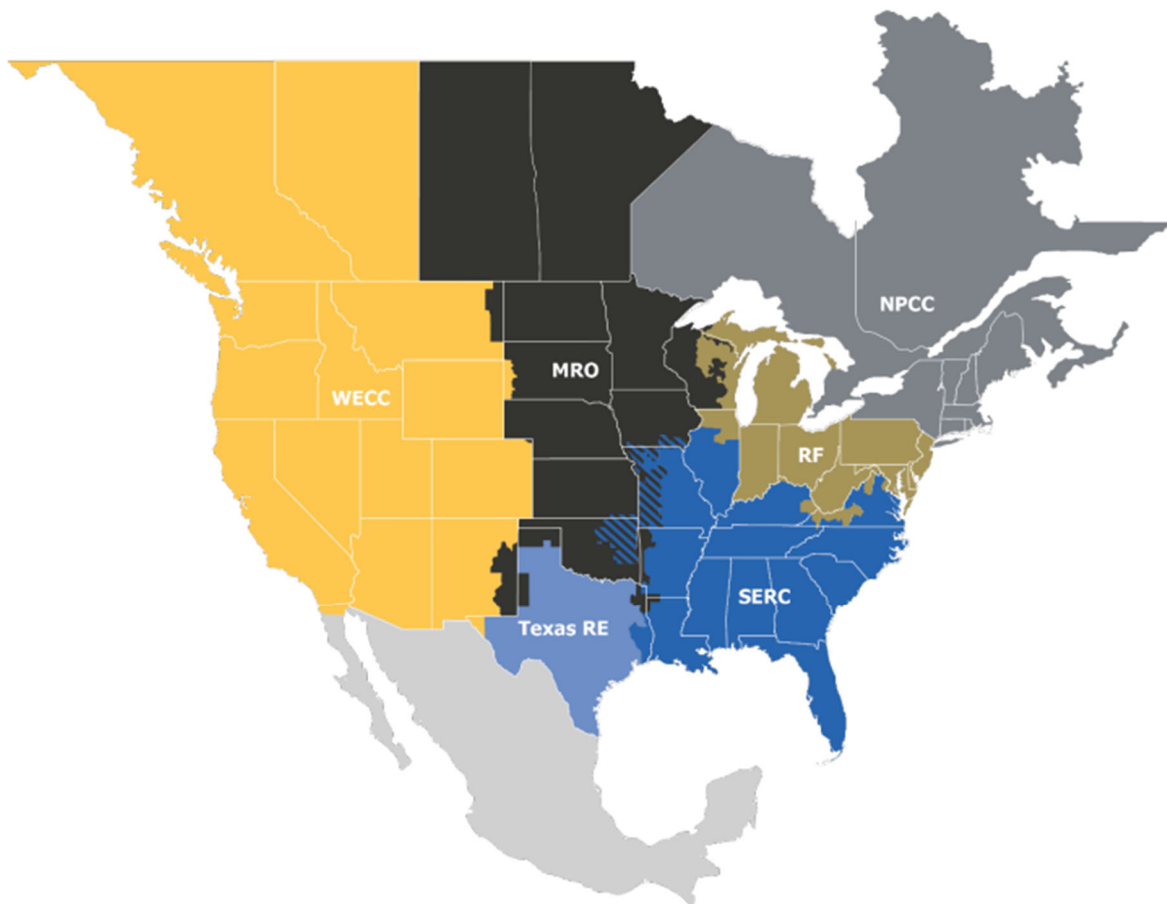


Figure 1.2: Regional Entity Boundaries



Chapter 2: 2026 Summer Outlook

Changing climate conditions have made seasonal load forecasting increasingly complex and difficult. The uncertainty associated with seasonal load forecasting has elevated summer reliability risks for the bulk power system. Extreme hot temperatures and severe weather can stress the grid and cause electricity demand to deviate significantly from historical forecasts. Underestimating demand may lead to ineffective operational planning and insufficient scheduling of resources, while overestimating demand can lead to adding excessive resources at consumers' expense. Additionally, generator performance and fuel supply issues are more likely to arise when generators are required to operate on short notice, exposing BAs to potential resource shortfalls.

In coordination with the ERO Enterprise and industry, MRO conducts seasonal generation and load forecasts to assess reliability risks. Details from the 2026 Seasonal Summer Forecast can be found in [Appendix B](#). Based on this information, the projected reliability conditions for each assessment area in the MRO region for the 2026 summer season are outlined below.

BY ASSESSMENT AREA

Manitoba Hydro

Manitoba Hydro's Anticipated Reserve Margin (ARM) decreased from 14.6% last summer to 13.2% this summer due to a rise in demand and extended outages on some of its smaller units. The demand growth is driven primarily by overall population and economic growth, including electrification of a large industrial customer to reduce carbon emissions. Manitoba Hydro's Installed Capacity (ICAP) Planning Reserve Margin Requirement (PRMR) remains unchanged at 12%.

Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for the upcoming 2026 summer season.

Manitoba Hydro reservoir storage conditions are below average, but winter snowfall has been above average, which will favorably impact spring runoff. The Manitoba Hydro system is designed and operated so that reliability can be maintained under extreme drought. Manitoba Hydro expects to reliably supply its internal demand and export obligations, even if extreme drought develops through 2026/27.

Midcontinent Independent System Operator

Midcontinent Independent System Operator's ARM increased from 24.7% last summer to 31.1% this summer, driven by anticipated resource additions, with a new record set for nameplate installations (primarily solar at 6.6 GW). Its ICAP PRMR decreased slightly from 15.7% percent last summer to 15% this summer, due to changes in resource capability under the summer 2026 seasonal capacity construct.

Demand forecasts and resource data indicate that Midcontinent Independent System Operator is likely to have adequate capacity to meet demand, as well as operating reserves, during periods of high demand.

Since the 2025 summer season, Midcontinent Independent System Operator has identified seven areas of focus to help address recent reliability and market concerns:

- Transmission system emergency response changes
- Operating reserve zone revisions
- Dynamic ramp requirements
- Elimination of dual registration for Emergency Demand Response (EDR) and Load Modifying Resources (LMR)



- Improvement on LMR / EDR / Demand Response Resource (DRR) type resources with the locational enrollment service
- Hybrid resource accreditation / participation
- Adoption of multiday gas purchase requirement

Saskatchewan Power Corporation

SaskPower Corporation's ARM decreased from 33.5% last summer to 29.2% this summer, mostly due to a rise in demand from residential and power class sectors. Contributing factors include population growth in the province, expansion projects, reduced self-generation in the industrial sector, and increased electrification across various customer groups. SaskPower Corporation's ICAP PRMR for the 2026 summer season remains unchanged at 15%.

Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat. Based on planned maintenance, typical forced outages from historical data, and expected renewable generation under normal and extreme demand conditions, SaskPower Corporation does not anticipate any reliability issues during the summer of 2026. However, during extreme summer conditions, there is risk for insufficient energy to serve load at peak hours, and SaskPower Corporation might need to utilize maintenance rescheduling, short-term power transfers from neighboring utilities, and/or available demand response programs.

Southwest Power Pool

The Southwest Power Pool East Assessment Area's ARM decreased from 28.5% last summer to 26.8% this summer due to increased demand. The Southwest Power Pool's East Assessment Area's accredited PRMR dropped to 10% compared to 19% coincident (15% non-coincident) peak demand last summer. This transition reflects the implementation of the new Southwest Power Pool East Assessment Area's Accredited Capacity (ACAP) PRMR.

Southwest Power Pool does not anticipate widespread reliability concerns under normal operating conditions for the 2026 summer season. However, operational challenges and emerging risks could impact system reliability under stressful conditions. Capacity margins continue to tighten due to increasing load growth and a changing resource mix, including greater reliance on variable energy resources. While planning reserve margins are expected to be met, energy adequacy risk remains during prolonged heat events aligned with low wind output. Additionally, the growing penetration of renewable resources introduces increased variability, ramping requirements, and challenges in maintaining essential reliability services like frequency response and voltage support.

Southwest Power Pool monitors transmission constraints and deliverability limitations, particularly during peak conditions when energy transfers may be restricted. Elevated forced outage rates across portions of the thermal fleet, combined with outage coordination challenges, increase operational uncertainty during high-demand periods. Extreme weather remains a key reliability driver, with the potential for regional conditions to increase demand, reduce generator performance, and limit imports due to the needs of the neighboring region. Emerging large load interconnections, including data centers and industrial facilities, further introduce forecasting and operational uncertainties. Overall, maintaining reliability will depend on proactive operational actions, enhanced outage coordination, and conservative operating practices during extreme or stressed scenarios.



Chapter 3: Historical Seasonal Trends

The following data was used to analyze system performance and identify seasonal trends:

- Bulk Electric System (BES) Event Analysis
- Energy Emergency Alerts (EEAs)
- Generation Availability Database System (GADS)
- Transmission Availability Database System (TADS)
- Misoperation Information Data Analysis System (MIDAS)
- Historical Summer Load Forecast

Performance data from GADS, TADS, MIDAS, and Event Analysis (EA) are collected and analyzed by MRO staff for the regional footprint. Resource and transmission system adequacy reviews are conducted by the Planning Coordinators (PCs) in the region within each respective area.

BULK ELECTRIC SYSTEM EVENT ANALYSIS

Mandated by Section 800 of the [NERC Rules of Procedure](#), MRO staff studies events and system disturbances that include significant losses of load or generation, or other emergencies on the bulk power system. Using the [Event Analysis Process](#) established by the ERO Enterprise, MRO works with registered entities to perform a root cause analysis of the event, develop a brief report, and document recommendations or lessons learned that can be shared with electric power industry stakeholders.

Transmission System Events

Eleven Category 1a transmission events occurred on the system in MRO's region in 2025, with three during the 2025 summer season. Equipment failure and protection system misoperations were identified as contributing causes. A Category 1a event results in an unexpected outage, contrary to design, of three or more BES Facilities caused by a common disturbance. (The NERC Addendum for Determining Event Category can be found at [NERC Addendum for Determining Event Category](#).)

MRO has published numerous lessons learned and two white papers addressing root causes identified through performance and event analysis to reduce misoperation risk. The Protective Relay Subgroup (PRS) updated and [republished two white papers](#) to consider more recent challenges and mitigation strategies. MRO staff continues to collaborate with industry experts on the PRS to reduce protection system misoperations.

Figure 3.1 illustrates MRO's Event Severity Index that includes all BES events and allows for comparison of the impact that each event had on the BES. Each section of the bar represents the calculated impact of the event using the number of elements lost, amount of generation lost, and amount of load lost. As an example, the event impact number for an event with 100 MW of load shed, 120 MW of generation lost, and eight BES elements taken out of service will be higher than the impact of an event with a low number in any of the named categories. The green bar is the average annual impact of all events, which MRO uses as a general indicator of how entities are limiting the impacts of events on the BES in the region.

MRO's primary focus is to limit large-impact events, especially those that may lead to a wide cascading event or outage. The total number of events over the five-year period shown on the chart has remained consistent year-over-year, while the average impact is trending downward.



A summary of BES events that occurred during the 2025 summer season in MRO's region, including the event category, number of BES facilities lost, MW of generation lost, and MW of load lost, is included in [Appendix C](#).

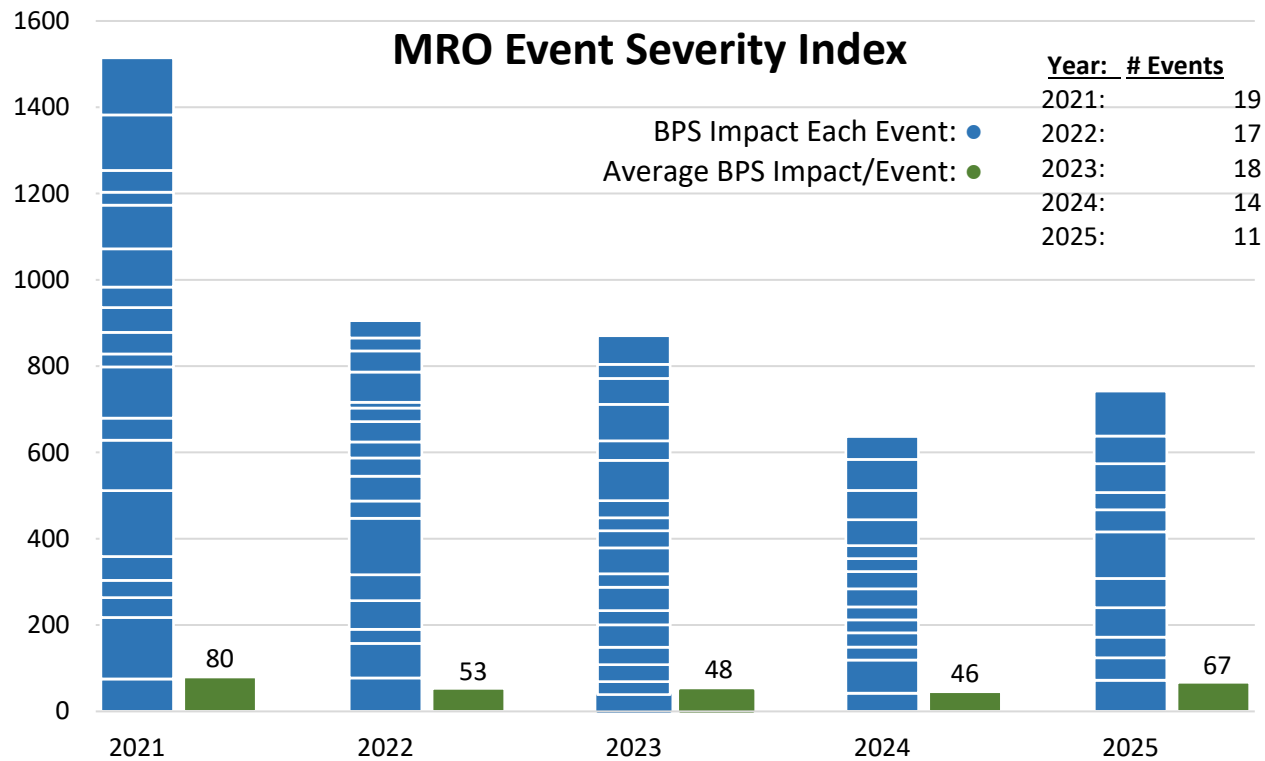


Figure 3.1: MRO Event Severity Index

Energy Management System Events

In 2025, four Category 1h Energy Management System (EMS) events occurred within the MRO region. One of these events took place during the 2025 summer season with a duration of 60 minutes. The average duration of the 2025 Category 1h events was 84 minutes. A Category 1h event results in the loss of monitoring or control at a control center such that it significantly affects the entity's ability to make operating decisions for 30 continuous minutes or more. (The NERC Reference Guideline for 1h events can be found at [Reference Guideline for Category 1h Events](#).)

A common factor among these events is that they occurred either during or shortly after a routine maintenance procedure. The number of EMS related events has decreased over the last five years, possibly due to mitigation recommendations in NERC lessons learned, webinars, and other outreach efforts. NERC's [Event Analysis Subcommittee \(EAS\)](#) provides registered entities with the opportunity to engage in discussions around significant events impacting the BES, event causal factors, the event analysis process itself, as well as supporting the development of lessons learned.

MRO encourages entities to participate in these initiatives as they provide the opportunity for industry-wide information and knowledge sharing.



Figure 3.2 compares the loss of EMS events that took place during the last five years. Each section of the blue bar represents the duration of each event in minutes. The green bar is the average duration of all the events for each year.

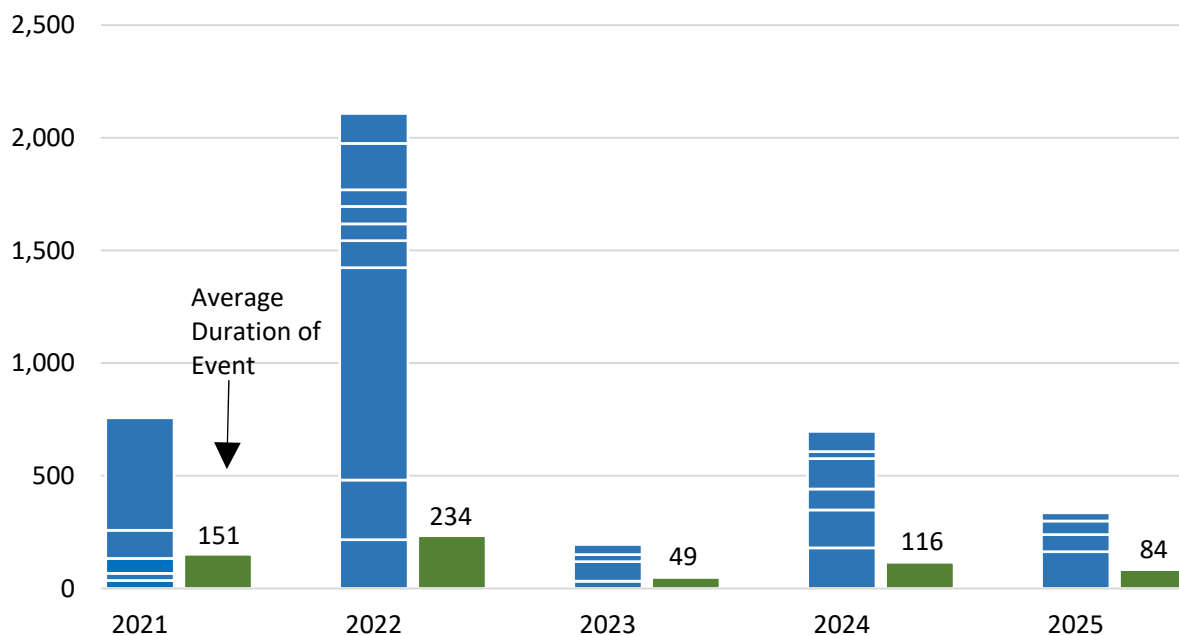


Figure 3.2: Loss of EMS Event Time Duration

ENERGY EMERGENCY ALERTS

An Energy Emergency Alert (EEA) occurs when a BA or load-serving entity exhausts all available resource options and cannot meet its expected load and operating reserves. EEAs are issued by RCs and are governed by NERC Reliability Standard [EOP-011-4](#) to ensure that TOPs and BAs have coordinated operating plans to mitigate emergencies.

The MRO region experienced one EEA level 3 and two EEA level 1 events during the 2025 summer season. A summary of the events is included in [Appendix C](#).

GENERATING AVAILABILITY

GADS is a program that collects information about the performance of electric generating equipment to assist with analyzing generation outages. [GADS data](#) has been reported since January 1, 2013, and includes information on more than 8,000 conventional generation units across North America. It is a valuable source of information on reliability, availability, and maintainability of generating units and includes unit design data, monthly performance data (including hours of availability and power produced), and event data. The ERO Enterprise has been capturing wind generation performance data in a separate GADS wind application since 2018, which has now been retired. GADS solar data was first collected in 2024, which was the first year for reporting events for GADS solar in the new data collection portal. This newly reported data is not included in this report but will be added once more information becomes available. Due to a change in GADS data reporting format in 2024, Manitoba Hydro data is not included in this report.



Generation unavailability can have a substantial impact on reliability. Useful metrics for generator unavailability are the equivalent forced outage rates (EFOR)³ and megawatt Weighted EFOR or WEFOR. Long-term trends indicate increasing WEFOR rates due to component fatigue and an aging fleet. Given higher penetrations of intermittent resources, conventional generation is being cycled (ramping up and down / startup and shutdown) to follow load and operating at minimum output more often, increasing the number of forced outages due to component failures.

Key Findings

- MRO is seeing a continuing upward trend in WEFOR in the generation fleet driven largely by winter and maintenance season performance.
- Summer performance was improved over the previous year, but more heavily impacted by ongoing outages from the spring maintenance cycle.
- Fossil steam, simple cycle contributed to higher event impacts and increased WEFOR percentages.

Based on forced outage rates for fossil-steam and simple cycle gas turbines, MRO closely monitors the performance (and identifies the failure risk) of these types of resources. Higher forced outage rates of fossil-steam and simple cycle gas could impact generation resource availability during extreme summer peak demand and increase the number and duration of EEA events.

More details on generation impacts are provided in [Appendix D](#).

TRANSMISSION AVAILABILITY

TADS is used to track the availability of AC/DC transmission circuits and transformers operating at 100kV and above. [TADS data](#) also includes detailed information about individual outage events, that when analyzed both regionally and North American-wide, provides useful data in reliability analyses. Momentary outages of less than one minute are only reported for elements at or above 200kV, while sustained outages of one minute or longer are reported for elements at 100kV and above.

Key Findings

- TADS-reportable outages were 5% lower than 2024 and 3% lower than the 5-year average.
- Lightning was the cause of 39% of the momentary outages reported in the 2025 summer season.
- The number of unknown momentary outages decreased by 53% compared to 2024. This is a considerable improvement from the 66% increase in 2024 over 2023.
- June 19 had the largest number of outages reported in a single day with 3.8% of the 2025 summer season.
- The three-day period of August 8-10 had 6.5% of the outages as two storms traveled across the southern portion of the MRO footprint.

Additional details on transmission outages are provided in [Appendix E](#).

³ The hours of unit failure (unplanned outage hours and equivalent unplanned derated hours) given as a percentage of the total hours of the availability of that unit (unplanned outage, unplanned derated, and service hours) - Alexander Eydeland and Krzysztof Wolyniec (2003). Energy and Power Risk Management. John Wiley and Sons. p. 109. ISBN 9780471455875



PROTECTION SYSTEM MISOPERATIONS

A properly functioning protection system is critical for maintaining reliability of the BES. Proper operation of protection systems is instrumental in preventing cascading events and large disturbances. A protection system misoperation is summarized as a failure of a composite protection system to operate as intended for protection purposes (the full definition can be found in the [NERC Glossary](#)).

Reporting of misoperations allows for causal analysis, overall trending across North America, and an opportunity to improve the effectiveness of mitigation measures. TOs, GOs, and Distribution Providers are required, per the NERC Rules of Procedure Section 1600 data request process, to report protection system operations and misoperations through MIDAS. A common measure using MIDAS data is a misoperation rate [misoperations) / (total operations)], which provides an industry measurement of protection system performance.

The annual ERO Enterprise misoperation rate is shown below in Figure 3.3 from the [2025 NERC State of Reliability](#) report.

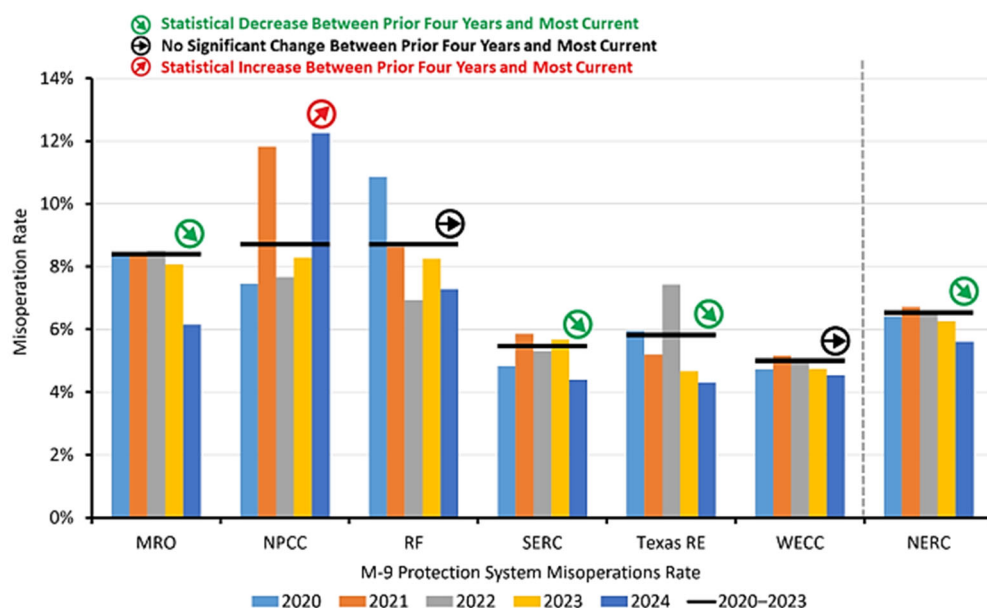


Figure 3.3: Changes and Trends in the Annual Misoperations Rate by Regional Entity

There were 3,127 operations and 198 misoperations reported in the MRO region in 2025 for a misoperation rate of 6.3%. Figure 3.4 shows the misoperation rate⁴ had been trending nearly flat since 2020. 2024 showed a marked decrease in the misoperation rate, which was sustained in 2025.

⁴ The misoperations rate data shown in Figure 3.4 was updated in 2024 to reflect final misoperation rates submitted through MIDAS for the five-year period. This resulted in nominal changes in the data reflected in this report compared to previously published seasonal assessments.

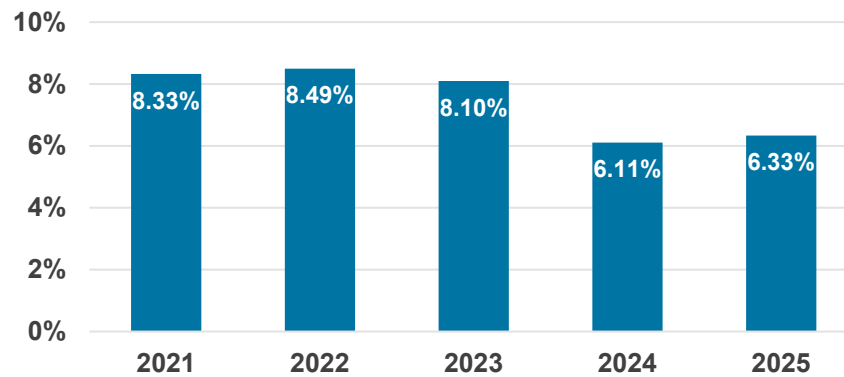


Figure 3.4: MRO Misoperation Rate by Year

Figures 3.5 and 3.6 provide context for the misoperation rate for 2025. Total protection system operations increased slightly, about 1%, in 2025 from the previous year, and total misoperations increased by approximately 5%, resulting in a slightly higher misoperations rate compared to 2024. Overall, Figures 3.4 and 3.5 show that 2025 was slightly above the five-year average for total operations and well below the five-year average for number of misoperations.

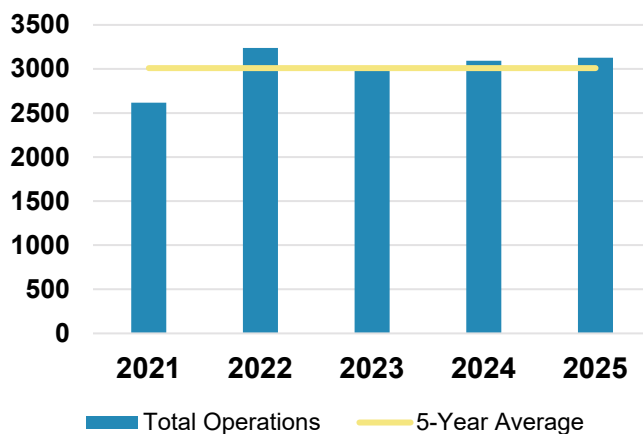


Figure 3.5: Yearly Protection System Operations

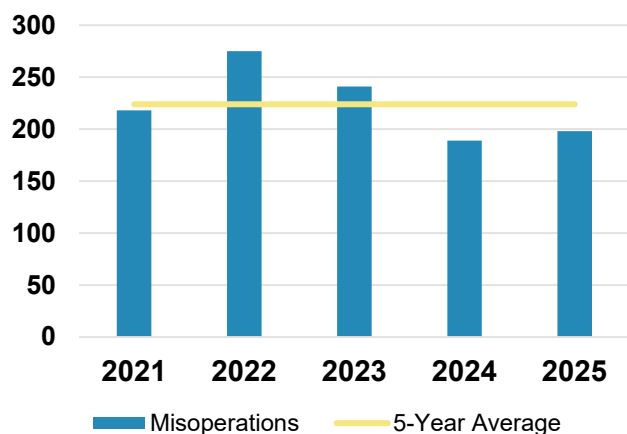


Figure 3.6: Yearly Protection System Misoperations

MIDAS reports are completed and reported by entities quarterly. The second (April-June) and third (July-September) quarters of the year align closest to the summer season (June-September) for this assessment.

As shown in Figure 3.7, more relay system operations occur on the MRO system in the spring/summer vs. autumn/winter. MRO attributes this disparity to more BES faults caused by more frequent and impactful summer weather events when compared to winter weather.



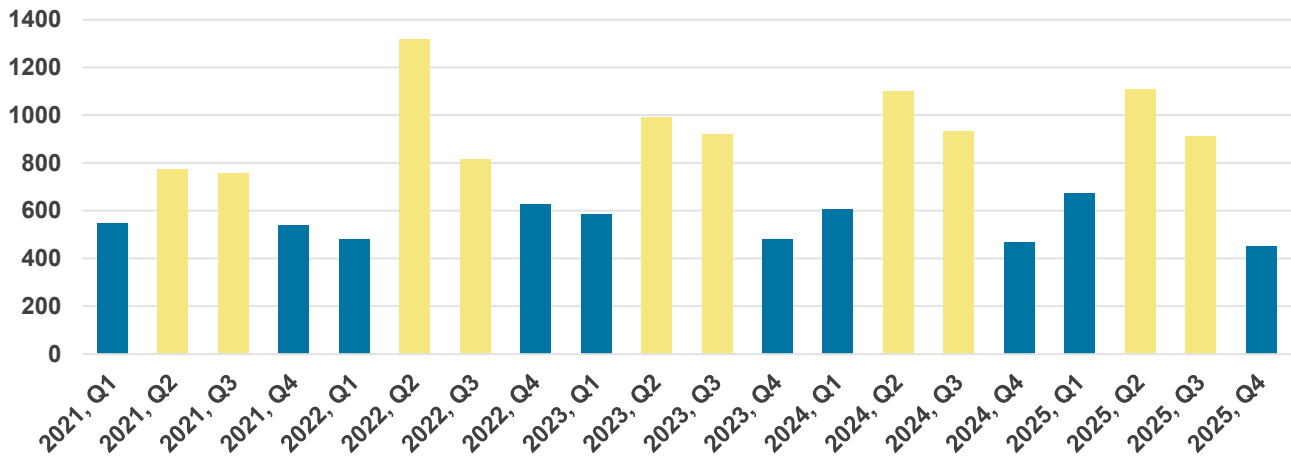


Figure 3.7: Total Operations (Spring/Summer vs. Autumn/Winter)

As shown in Figure 3.8, many misoperations are not associated with a fault. Non-fault-associated misoperations have a smaller annual variance than misoperations associated with a fault and do not vary from the number of correct protection system operations. Therefore, these misoperations would have a larger impact on the overall misoperation rate if the total number of protection system operations is low.

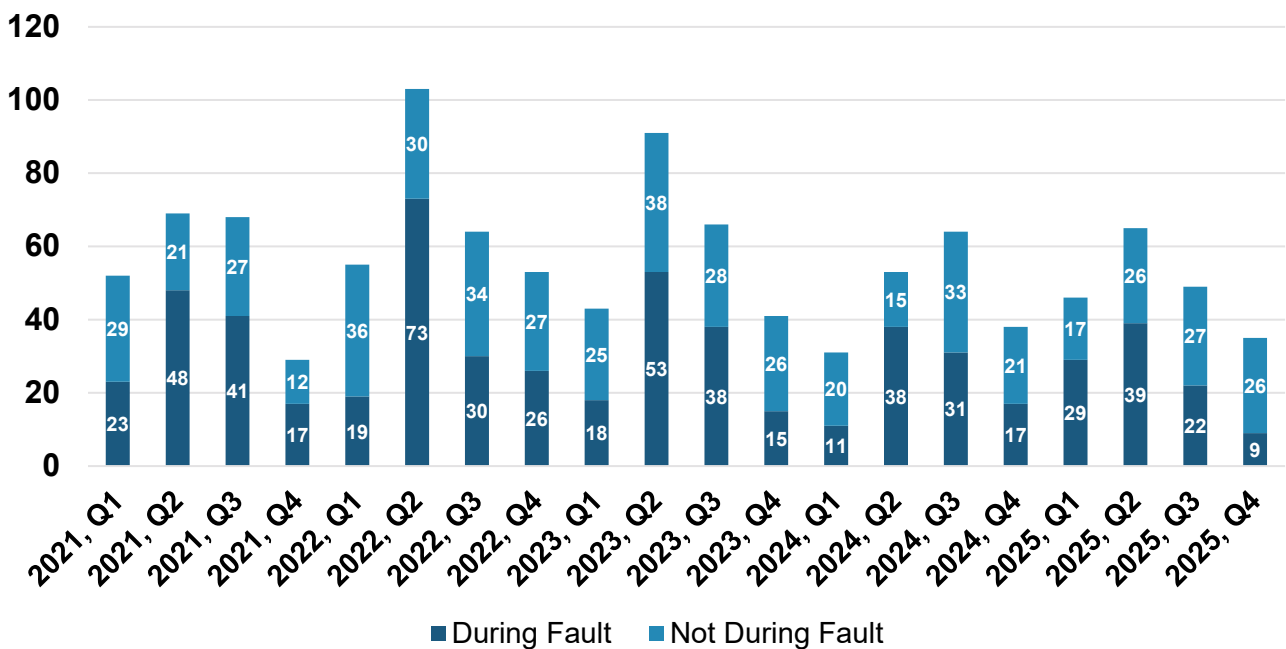


Figure 3.8: Fault Associated and Non-Fault Associated Misoperations



There were a total of 78 misoperations that occurred in the MRO region between June 1, 2025, and September 30, 2025. Examining these misoperations reveals several areas for improvement. As illustrated in Figure 3.9, of the 78 misoperations that occurred during this time, 49% were attributed to human errors (i.e., as-left personnel errors, design errors, incorrect settings, and logic errors) and 36% to equipment failures (i.e., relay failures/malfunctions, AC system, and DC system).

This trend underscores the importance of ongoing equipment maintenance and testing and reviewing obsolescence plans to ensure system reliability over time. With the higher number of protection system operations in spring/summer seasons, higher relay failure/malfunction rates during those seasons may coincide with the increased operational demand.

Although misoperations on the bulk power system stemming from human error have declined, a significant portion of misoperations in the MRO region remain attributed to human error causes. The following efforts help to reduce human error-related misoperations:

- Commissioning best practices and challenges are being discussed by MRO's Protective Relay Subgroup, which is an industry-led group comprised of utility companies and MRO staff.
- NERC hosted a third annual BES Protection System Misoperation Reduction Workshop at MRO's headquarters on October 7-8, 2025.

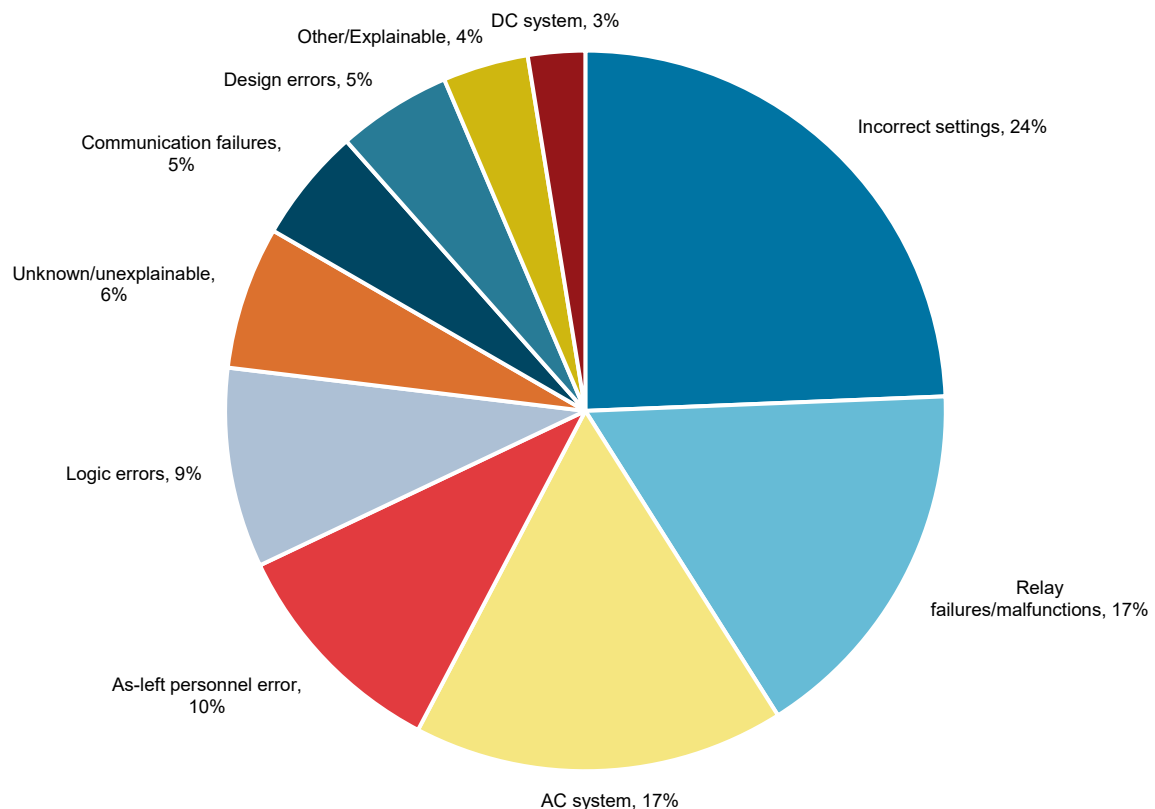


Figure 3.9: Summer 2025 Misoperations by Cause



HISTORICAL SUMMER LOAD FORECAST

To account for weather effects as accurately as possible, entities provide a forecast based on normal weather or assumed temperatures consistent with approximately the past 30 years of meteorological data. This is also referred to as the 50/50 forecast, which means that each year, the probability of the projected peak load being exceeded is 50%, while the probability that the actual peak load would be less than predicted is also 50%. A 90/10 forecast is a worst-case, extreme weather scenario that can be reasonably anticipated. It means there is only a 10% probability of the projected peak load being exceeded and there is a 90% chance that the actual peak load would be less than predicted. In other words, the forecast would exceed, on average, only once every ten years.

Figure 3.10 shows the five-year historical summer normal (50/50) and extreme (90/10) forecasts, actual and all-time summer peak load for each assessment area in the MRO region.



Figure 3.10: 5-Year Historical Summer Load Forecast



The extreme peak load forecast for the upcoming summer season is:

- Manitoba Hydro: 3,620 MW
- Midcontinent Independent System Operator: 122,714 MW
- SaskPower Corporation: 3,730 MW
- Southwest Power Pool: 58,118 MW

The highest historical summer hourly average demand recorded over the last five years is:

- Manitoba Hydro: 3,679 MW in June 2023
- Midcontinent Independent System Operator: 124,900 MW in August 2023
- SaskPower Corporation: 3,669 MW in July 2023
- Southwest Power Pool: 56,184 MW in August 2023

Actual weather conditions that occurred at the time of peak load can then be compared to the forecasted weather prediction to determine if any adjustments are warranted at the forecasted peak. This is particularly important for Midcontinent Independent System Operator and Southwest Power Pool, whose BA footprints span from the Canadian border to the Gulf of Mexico and can experience significant weather diversity on any given day.



Chapter 4: Emerging Risks

LARGE LOAD GROWTH

Growth in large load parcels like data centers and industrial facilities poses various challenges for system planners and operators. Large parcels of load on the system increases uncertainty in peak and hourly load forecasting. Moreover, determining how much of the current forecasted load will be installed further complicates planning efforts.

Large load development timelines are often much shorter than the timelines for building new power generation and transmission infrastructure. If data center and industrial facility growth rates surpass that of area resources, the risk of load loss increases.

GENERATION RESOURCE MIX

MRO's 2026 summer peak installed and accredited capacity reflects a diverse mix of fuel types, as shown in Figure 4.1. The largest single contributor by peak capacity in the region is natural gas, with approximately 54% of installed capacity located in the southern portion of the region. Coal plants and wind turbines make up the next largest portions of the generation mix. Battery energy storage systems (BESS) do not currently represent a significant share or portion of the regional generation resource mix.

Conventional generation, such as coal, steam, hydro, and combustion turbines, which have a large rotating mass capable of providing essential reliability services like frequency and voltage support, is gradually being retired.

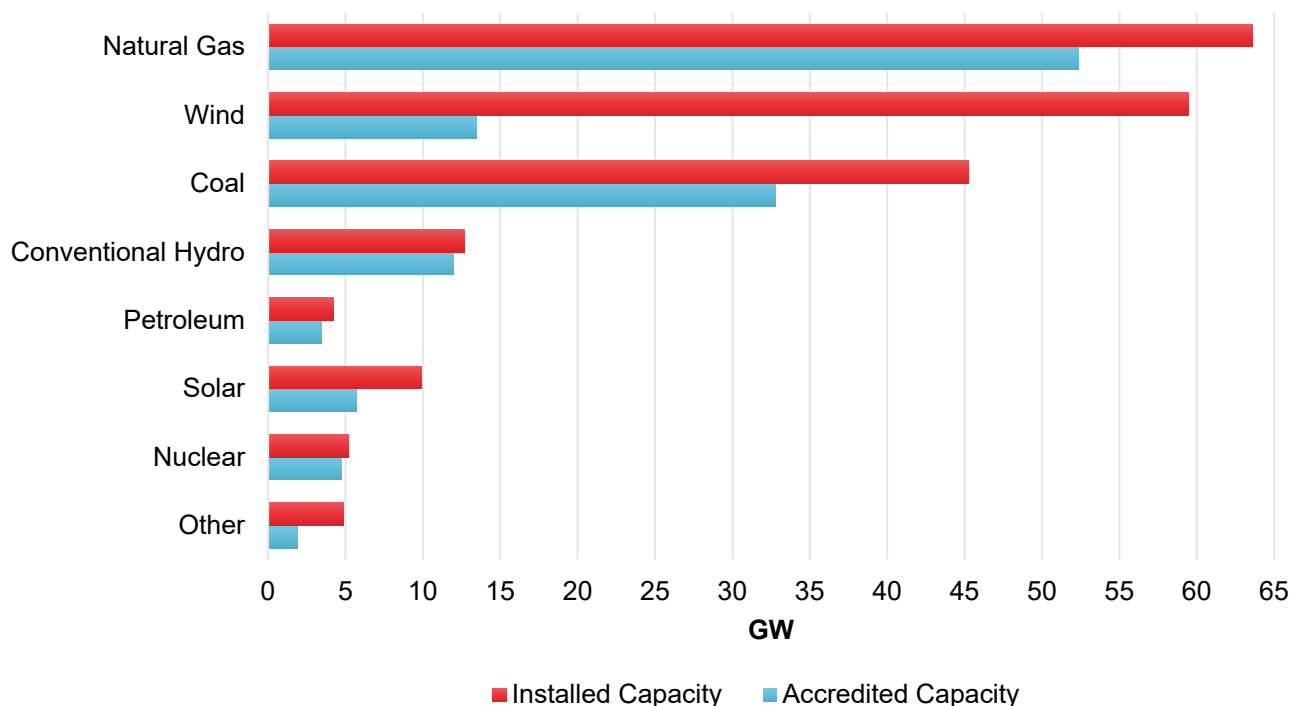


Figure 4.1: MRO 2026 Summer Peak Installed and Accredited Capacity by Fuel Types

The growing share of intermittent resources, such as wind and solar, is adding operational complexity in resource commitment and dispatch. Forecasting inaccuracies can lead to larger, unexpected energy shortfalls or excesses in real-time operations, making it difficult to predict ramping changes.

Wind

The MRO region has 59.4 GW of existing installed wind capacity, with 13.5 GW (23%) accredited for the 2026 summer peak season. Multiple proposed projects in the Midcontinent Independent System Operator and Southwest Power Pool generation interconnection queues could add approximately 23.8 GW of installed wind capacity by 2035. Operational challenges related to large amounts of wind power include difficulties in accurately forecasting wind output, impacts on conventional resource cycling, transmission capacity or voltage constraints, and limited inertia to provide voltage and frequency support compared to conventional generation.

Solar

Utility-scale solar photovoltaic (PV) installations are rapidly increasing in the MRO region and are projected to become the second most prominent renewable energy source after wind. The MRO region has 9.9 GW of existing installed solar capacity, with 5.7 GW (58%) accredited for the 2026 summer peak season. Approximately 22.6 GW of solar projects are being proposed in the Midcontinent Independent System Operator and Southwest Power Pool interconnection queues by 2035. Operational challenges related to large amounts of solar resources include forecasting and managing daily ramping changes at sunrise and sunset.

SUMMARY OF RISK

Not every project in the interconnection queue will be constructed, as some may be withdrawn after completion of system impact studies that determine transmission upgrades required for project integration. The transition from conventional generation to intermittent resources requires BAs to maintain flexible resources that can ramp quickly in response to fluctuations in output from intermittent sources and load variability. Conventional steam units, especially those designed for base load, generally have lower ramp rates, and were not built to handle frequent cycling, which can increase forced outage rates and maintenance needs.

These factors elevate the risk of insufficient resources to serve load during periods when renewable output falls short of forecasts. This challenges control room operators, especially when there is high uncertainty in intermittent resource output and significant ramping events. As a result, BAs are forced to carry additional operating reserves to manage forecast uncertainties for wind and solar, as well as load forecasting errors.

Moreover, with more intermittent resources in the mix and the retirement of conventional generation, it is becoming increasingly difficult to schedule planned outages for conventional generating units. The higher unpredictability of intermittent resource output means BAs rely more heavily on conventional resources during off-peak maintenance periods. This introduces scheduling complexities for planned maintenance that typically use the same labor resources, while at the same time need to ensure reliable load service. Additionally, increased ramping of conventional units due to intermittent resource challenges accelerates maintenance requirements, further complicating maintenance scheduling and labor resource utilization for these resources.



Chapter 5: Summary

FOCUS AREAS FOR 2026 SUMMER

MRO's independent evaluation of the generation and transmission systems for the 2026 summer season has identified the following key focus areas and potential operational concerns:

- **Electricity Supply Shortfalls:** SaskPower Corporation faces risk of electricity supply shortfalls during extreme summer conditions. SaskPower Corporation has sufficient capacity/reserve margin to meet peak summer demand however there are risk(s) for insufficient energy to serve load for all hours.
- **Variably Energy Resource Performance:** With the increased penetration of wind and solar in the MRO region, the performance of this generation during periods of high demand is crucial in determining whether the electricity supply will be sufficient to meet system demand.
- **Conventional Generation Outage Rates:** WEFOR for conventional generation in 2025 remained higher than the five-year moving average. Long-term trends show increasing forced outage rates, partly due to the cycling of conventional generation beyond its original design limits, driven by higher penetrations of intermittent resources. This cycling can lead to component failures.
- **Sustained Transmission Outages:** In four of the past five years, failed AC circuit equipment has continued to be the leading contributor to sustained transmission line outages during summer months.
- **Protection System Misoperations:** Protection system misoperations remain a leading cause of major events in the MRO region. Human error accounted for 49% of last summer's misoperations, with just under half of these resulting from incorrect settings.



Appendix A: Registration and Certification

REGISTRATION

There are 291 entities (NCR IDs) registered in the MRO region ([NERC Compliance Registry \(NCR\)](#)) as of the date of this publication. These users, owners and operators of the bulk power system are deemed material to reliability because they meet specific criteria or perform certain functions. The number of registered entities on the NCR fluctuates with the addition of new entities and/or changes to existing entities' operational structure and functions. Which mandatory NERC Reliability Standards and requirements are applicable depends on how an entity is registered and the functions it performs. Registration information is fundamental to reliability assessments in that certain functions pose greater risk to reliability of the bulk power system.

The functional relationships identified in the NERC Rules of Procedure, Reliability Standards, and important entity relationships are part of an entity's registration record. All BAs and TOPs are required to be under the responsibility of one RC. Transmission facilities must be the responsibility of one TP, PC, and TOP. Loads and generators shall be the responsibility of one BA. RCs, BAs, and TOPs, along with GOs and GOPs, have an important role in maintaining reliability during normal and complex weather operations. These entities provide accurate operational data for ERO Enterprise event analysis. Generator modeling data provided by GOs and GOPs is utilized by TOPs, BAs and RCs, and is critical for use in operations planning and real-time analysis of the bulk power system.

Registration growth over the past five years has predominantly been with the GO and GOP functions. The increase in entities registered as GOs and GOPs is due to the decline of vertically integrated utilities and the deregulation of the supply side of the industry, combined with an increase in renewable resources. With the increasing integration of Inverter Based Resources (IBRs), NERC's Category 2 GO/GOP registration criteria were established and implemented to register owners and operators of bulk power system-connected IBRs with a nameplate rating of 20 MVA or more connected at 60kV and above.

The registration of Category 2 GOs/GOPs began in August 2025. The [NERC Inverter-Based Resources Work Plan](#) (phase 3) required all candidates that met Category 2 criteria be registered by May 15, 2026. Of the more than 100 bulk power system-connected IBR assets initially identified by NERC as subject to registration in the MRO region, MRO staff found 60 to meet the Category 2 criteria. In the end, MRO added 88 Category 2 functional scopes to its registry under the responsibility of 50 different organizations (unique entity NCR IDs). While 21 of these entities added the Category 2 functional scope to an active NCR ID, 29 were registered under new NCR IDs and/or the entity added the MRO region to its functional scope responsibility.

Additional resources found to meet criteria through the IBR Registration Initiative (those with commercial operations dates after May 15, 2026) will process per the [ERO Registration Procedure](#).



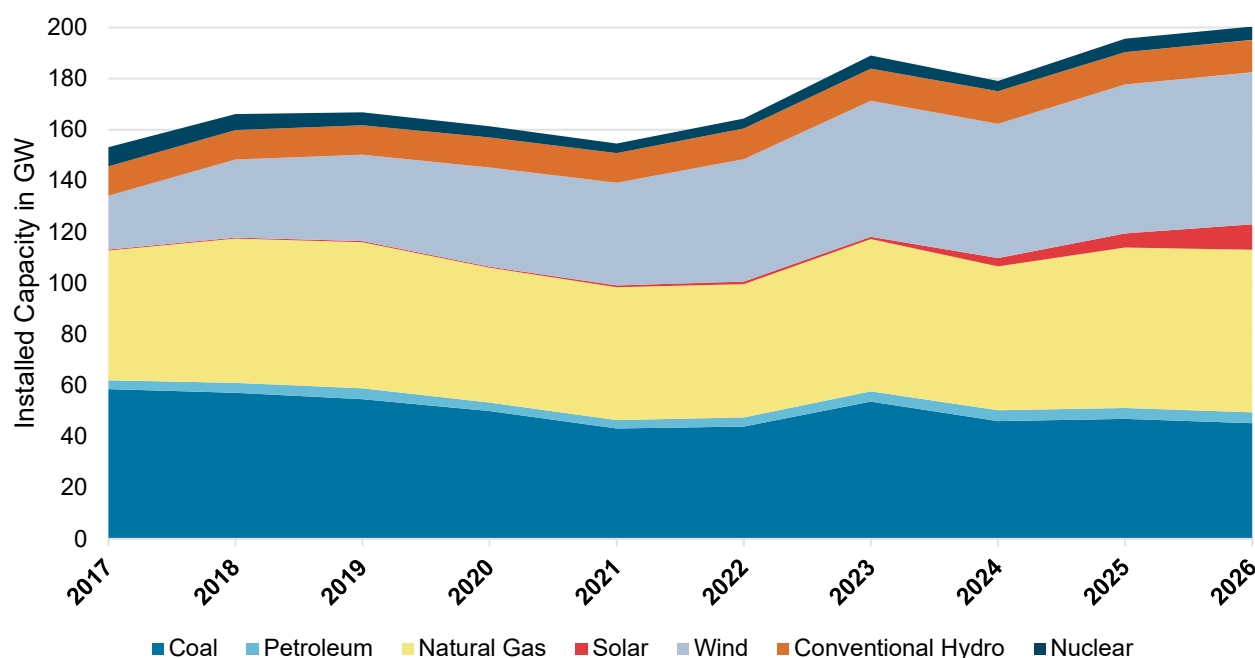


Figure AA1: MRO Historical Resource Mix by Fuel Types

CERTIFICATION

Real-time actions of RCs, TOPs, and BAs impact the reliable operation of the bulk power system. [ERO Enterprise Certification](#) activities provide regional assurance that the processes, procedures, tools, and training a registered entity applies in the performance of its functions meet the reliability obligations of registration. A registration candidate is required to complete the certification process for any new BA, RC, or TOP registered function. Material changes to already certified and operational registered entities require a review of conditions by the Regional Entity. The decision to certify changes to an already operating and certified registered entity is a collaborative decision between MRO and NERC.

During the first half of 2026, MRO completed one certification program activity. Currently, MRO has over 30 certification cases initiated and active. In addition to these active/in progress activities, MRO is evaluating one submission of change event and one TOP registration application. MRO anticipates more submissions before year end due to EMS modifications related to the industry changes required by FERC order 881 and the commission's approved extensions.

The Certification Program includes Certifications and Review of Conditions to identify issues that if not resolved, may lead to inadequate performance of duties and responsibilities applicable to the function. Fifty-seven functional registrations in the MRO region are applicable to the Certification Program.

This seasonal reliability assessment was developed based on data collected during performance analysis, event analysis, and situational awareness activities and directly focuses on RCs, TOPs, and BAs. The assessment provides reliability insight for the certification program and its activities. The roles fulfilled by the three functions (RC, BA, and TOP) are critical to the functional relationships within and between electric areas.



Appendix B: Summer Seasonal Forecast

The 2026 summer seasonal forecast includes the months of June 2026 through September 2026.

ANTICIPATED SUMMER RESOURCE AND PEAK DEMAND SCENARIO

Peak demand (or load) is the highest electrical power demand that occurs over a specific period and is typically characterized as daily, seasonal, or annual. The changes in demand levels are generally predictable and have daily, weekly, and seasonal patterns. The annual peak of hourly, daily, and monthly demand typically occurs during the summer or winter due to higher cooling or heating needs. Figure AB1 illustrates the 2026 anticipated, and the nine-year historical generation by fuel type at the time of summer peak for each of the PCs in the MRO region.

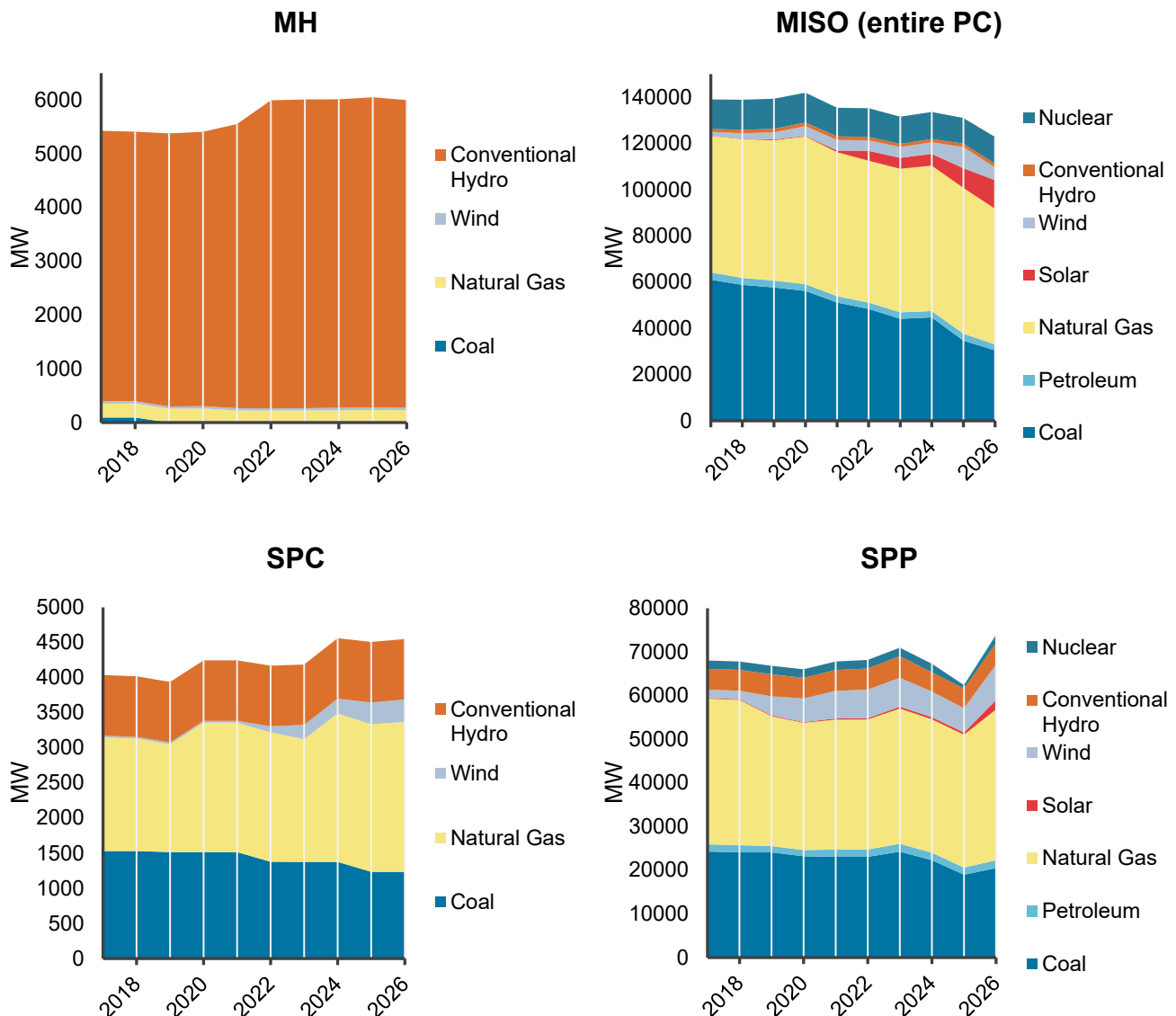


Figure AB1: Generation by Fuel Type at Time of Summer Peak



Each PC has a different resource mix. While Manitoba Hydro is predominantly conventional hydro, the resource mix in Midcontinent Independent System Operator, SaskPower Corporation, and Southwest Power Pool consist primarily of coal and natural gas with increasing amounts of wind in Southwest Power Pool. Because intermittent resources like wind and solar are weather dependent, forecasted on-peak wind and solar capacity contributions are based on historic average values and can be substantially less than ICAP.⁵ Midcontinent Independent System Operator and Southwest Power Pool wind and solar capacity accreditation is significantly lower than the total existing ICAP values for this reason. As penetration of intermittent resources increases, forecast errors in the output of intermittent resources available in the short-term (hours or days) can have a greater impact. BAs may need to increase operating reserves to account for the uncertainty in short-term resource output.

Rooftop solar, battery storage, and other distributed, behind-the-meter generation resources are having a dramatic impact on the load shape and the ability to forecast net demand (total demand less behind the meter resource output). When coupled with the anticipated increase in demand (e.g., electric vehicle charging, cryptocurrency mining, data centers, hydrogen production, and other electrification efforts), future load forecasts and patterns will likely change dramatically from what they are today.

Fossil-steam, gas, and petroleum generating plant cooling systems are less effective when cooling water input temperatures are higher. This can lead to reduced output in the summer months. The increase in cooling water temperatures and low river water levels that can occur in summer may impact generators with once-through cooling, thereby reducing output capability. Environmental limitations on discharge temperatures can lead to similar restrictions. The extreme peak demand scenarios in Tables AB3 and AB4 examine how extreme or prolonged hot temperatures over a large area could impact the generation resource adequacy. Resources throughout the extreme scenarios are compared against expected reserve margin requirements based on peak load and normal weather. The effects from low-probability events are also factored in through additional resource derates. For example, maximum historical outages minus the average of both maintenance and forced outages for non-intermittent resources or low-output scenarios (such as a wind resource output adjustment due to low-wind), and additional load based on extreme weather conditions.

The [90/10 peak load](#) weather forecast methodology is used to model the reliability risk of the actual system peak exceeding the forecasted [50/50 peak load](#) due to load forecast uncertainty. The industry uses this traditional methodology and assumption to ensure energy availability through increased dispatchable resource capacity so that adequate resources are available during higher than anticipated peak demand. However, recent increases in extreme weather events and unavailability of energy during off-peak hours (e.g., low wind production) presents new challenges, in part due to the retirement of dispatchable resources and the rapid growth of fuel sources that are weather dependent and inherently less predictable (like wind and solar).

As a result, an ERO Enterprise cross-functional working group comprised of experts in multiple industries within the energy sector, including representatives from fuel supply and delivery chains (e.g., fuel oil and natural gas) and the electric grid will report to NERC's Reliability and Security Technical Committee. The [Energy Reliability Working Group \(ERWG\)](#) will serve as an informational stakeholder forum open to cross-sector organizations to facilitate ongoing assessment of energy-related risks to the balance of supply and demand on the North American bulk power system. This working group will also develop documents to

⁵ The maximum amount of capacity a generator can produce. ICAP can be considered in two different ways: nameplate capacity rating in MW or seasonal net dependable capacity rating that accounts for ambient temperatures and humidity during the season.



clarify energy reliability issues and best practices for assessing energy risks and identify potential responsive measures associated with unassured energy supplies.

The electric power industry needs to develop new and enhanced forecasting methods and new metrics to evaluate energy availability required to support reliable and secure operations of the bulk power system at all times.

The following definitions are used for the risk scenario analysis:

- **Anticipated Resources:** Existing resources plus Net Firm Transfers plus Planned resources in MW.
- **Typical Maintenance Outages:** Historical average of generator maintenance outages in MW for specified period/conditions, (e.g., average of maintenance outages for December through February weekdays, over the past three years) or area-specific methodology for determining anticipated maintenance outages.
- **Typical Forced Outages:** Historical average of forced generator outages in MW for a specified period/conditions (e.g., average of forced outages for December through February weekdays, over the past three years), or area-specific methodology for determining anticipated forced outages for non-intermittent resources (e.g., thermal, hydro).
- **Normal Peak Load:** Peak hour demand forecast in MW based on normal weather. This is also referred to as the 50/50 peak load forecast.
- **Reserve Margin:** The amount of generation capacity in MW available above projected load to reliably meet expected demand.
- **Extreme Resource Derates:** Reduced capacity contribution in MW due to generator resource performance in extreme conditions (e.g., temperature-based derates; or based on severe historical events).
- **Extreme Peak Load:** Sum of Normal Peak Load and seasonal load adjustment in MW for extreme weather conditions (e.g., 90/10 peak load forecast; or based on severe historical events).
- **Extreme Low Generation:** Anticipated Resource minus Typical Forced Outages and Extreme Derates in MW.

Several risk factors and criteria are used when determining the risk levels (low, medium, and high) for an assessment area that is likely to issue Energy Emergency Alerts, or EEAs. This includes meeting the reference margin levels, the loss of load expectation and the availability of sufficient operating reserves under normal and extreme peak demand. The anticipated resources for conventional generators are based on ICAP or slightly lower accredited capacity, which represents physical generating capacity adjusted for ambient weather conditions. Intermittent renewables, such as wind and solar, capacity contributions are based on historic average values or [Effective Load Carrying Capability \(ELCC\)](#). Table AB2 displays anticipated reserve margins with normal peak load projections for each assessment area. The normal peak load projections are based on 50/50 weather forecasts and are provided on a coincident⁶ basis for the assessment areas. Manitoba Hydro, Midcontinent Independent System Operator, SaskPower Corporation,

⁶ Sum of two or more peak loads that occur in the same hour.



and Southwest Power Pool have sufficient resources to meet their PRMR under normal peak summer conditions.

Assessment Area	Anticipated Resources	Normal Peak Load	Anticipated Reserve Margin	PRMR	Likelihood to Issue EEAs
MH	3,917	3,460	13.2%	12.0%	Low
MISO	155,641	118,725	31.1%	15.0%	Low
SPC	4,699	3,638	29.2%	15.0%	Low
SPP	70,168	55,350	26.8%	10.0%	Low

Table AB2: Anticipated Reserve Margin Percentage with Normal Peak Load

Manitoba Hydro, Midcontinent Independent System Operator, SaskPower Corporation, and Southwest Power Pool anticipate reserve margins that reflect robust amounts of excess capacity, there is still potential risk of energy shortfall based on past performance during extreme weather events.

Based on the normal peak load forecast with typical maintenance and forced outage scenario shown in Table AB3, Manitoba Hydro, Midcontinent Independent System Operator, SaskPower Corporation, and Southwest Power Pool have sufficient resources to meet their operating reserve requirements under normal peak summer conditions with typical maintenance and forced outages.

Assessment Area	Anticipated Resources	Typical Maintenance and Forced Outages	Anticipated Resources with Typical Outages	Normal Peak Load	Anticipated Reserve Margin with Typical Outages	Likelihood to Issue EEAs
MH	3,917	130	3,787	3,460	9.5%	Low
MISO	155,641	11,272	144,369	118,725	21.6%	Low
SPC	4,699	217.3	4,482	3,638	23.2%	Low
SPP	70,168	2,977	67,191	55,350	21.4%	Low

Table AB3: Reserve Margin Percentage with Typical Outages and Normal Peak Load

The scenario shown in Table AB4 considers typical maintenance and forced outages combined with extreme summer peak load forecast. For this scenario, Manitoba Hydro, Midcontinent Independent System Operator, SaskPower Corporation, and Southwest Power Pool have sufficient resources to meet operating reserve requirements under extreme peak summer conditions with typical maintenance and forced outages.

Assessment Area	Anticipated Resources with Typical Outages	Extreme Peak Load	Reserve Margin Under Extreme Peak Load	Likelihood to Issue EEAs
MH	3,787	3,620	4.6%	Low
MISO	144,369	122,714	17.6%	Low
SPC	4,482	3,730	20.2%	Low
SPP	67,191	58,118	15.6%	Low

Table AB4: Reserve Margin Percentage with Typical Outages and Extreme Peak Load



The worst-case scenario for the 2026 summer season considers increased resource outages and derates combined with an extreme peak load forecast as shown in Table AB5.

Assessment Area	Anticipated Resources with Typical Outages	Extreme Resource Derates	Extreme Low Generation	Extreme Peak Load	Reserve Margin Under Extreme Resource Derates and Extreme Peak Load	Likelihood to Issue EEAs
MH	3,787	10	3,777	3,620	4.3%	Low
MISO	144,369	16,937	127,433	122,714	3.8%	Low
SPC	4,482	479.3	4,002	3,730	7.3%	Medium
SPP	67,191	6,850	60,341	58,118	3.8%	Low

Table AB5: Reserve Margin Percentage with Extreme Resource Derates and Extreme Peak Load

The extreme low generation in Table AB5 shows marked improvement in expected reserve margin compared to the 2025 summer season, with SaskPower Corporation being the only region with a medium risk profile. Even though SaskPower Corporation has a much higher reserve margin compared to other assessment areas, its probabilistic energy analysis indicates there is risk for insufficient energy to serve load for all hours for the 2026 summer season.

SaskPower Corporation experiences peak loads in winter months, however, the risk of operating reserve shortages or EEAs during extreme summer peak loads (like what was experienced during the 2023 and 2024 summer heatwaves) remain if a major unplanned generation outage coincides with large generation maintenance outages. SaskPower will activate demand response programs, implement short-term power imports from neighboring utilities, and, if necessary, implementing temporary load interruptions to maintain grid stability.

WIND AND SOLAR RESOURCES

Midcontinent Independent System Operator and Southwest Power Pool continue to see an increase in wind and utility-scale solar photovoltaic penetration in the region. Figure AB6 reflects the summer season wind and solar photovoltaic ICAP and peak capacity for each of the assessment areas. The peak capacity value is the accredited ELCC amount of wind or solar available during the period of peak demand. ELCC is defined as the amount of incremental load a particular type of resource, such as wind or solar, can dependably and reliably serve, while also considering the probabilistic nature of generation shortfalls and random forced outages.

The ELCC amount also varies with the resource mix of the system being evaluated. This results in decreasing ELCC values as renewable penetration becomes higher and conventional resources are retired, at times much lower than the ICAP value.



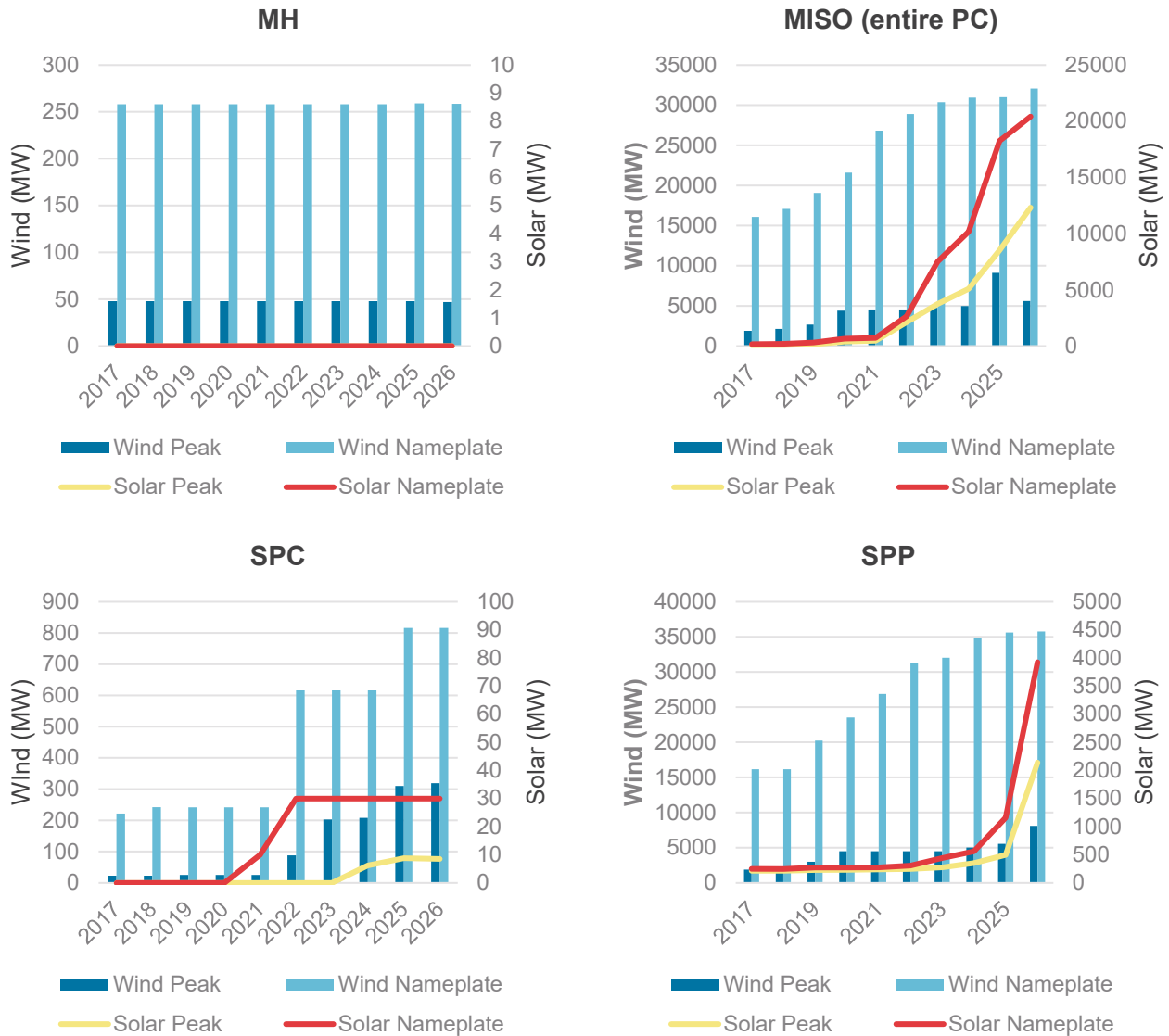


Figure AB6: Wind and Solar Photovoltaic Summer ICAP and Peak Capacity

The rapid growth of inverter-based resources (IBRs) is the most significant driver of grid transformation and poses a high risk to bulk power system reliability. The new NERC registration criteria for Category 2 IBRs will result in an increase in existing and future wind and solar capacity in the MRO region. Bulk power system-connected wind and solar power resources are growing in the MRO region and combined, could reach as much as 115.7 GW by 2035.

When implemented correctly, inverter technology can provide significant benefits for reliability of the power grid. However, it can introduce significant challenges for power grid planners and operators if not integrated properly. Performance issues, such as wind plants shutting down under high winds during storms and solar panels losing efficiency from high ambient temperatures, or storms and cloud cover, can have a significant impact on reliability of the bulk power system.

Appendix C: BES Event and EEA Details

August 1, 2025 - Transmission Event

Event Category: 1.a

- 5 BES Facilities interrupted
- 5 MW of generation lost
- 0 MW of load lost

At 17:31 on August 1, 2025, a lightning strike resulted in the operation of a 138kV transmission line. Following that correct operation, a misoperation occurred at one of the 138kV terminals resulting in multiple breakers operating due to a breaker failure lockout operation.

It was determined that the cause was incorrect settings.

The entity queried their database to identify any reoccurrence of the error identified as the cause of this event. One instance was found in a relay at the same site and corrected.

August 21, 2025 - Transmission Event

Event Category: 1.a

- 4 BES Facilities interrupted
- 0 MW of generation lost
- 0 MW of load lost

On August 21, 2025, at 13:17, while performing switching to return a 115kV line breaker to service following a relay replacement, the C phase bus differential relay operated and tripped the 115kV main bus lockout relay, tripping three 115kV lines and opened the 115kV terminal of a 230/115kV transformer. Hydraulic system problems were identified on one of the breakers as the cause of the event.

There was no customer load lost during this incident.

September 3, 2025 - Transmission Event

Event Category: 1.a

- 3 BES Facilities interrupted
- 172 MW of generation lost
- 0 MW of load lost

On September 3, 2025, at 10:27:00 AM, the entity was undergoing a monthly inspection on a 230/13.8kV unit transformer for one of their 86 MW generators. The transformer fan control was set to manual, as part of the routine maintenance steps. The vibration from the fan control switch movement tripped the fast gas relay which then tripped a 138kV transmission line and two 86 MW generators.

The fast gas relays were mounted on anti-vibration mounts and were found to have dried out and broken.

The entity has added a warning card on the fan controls and has a repair scheduled for the degraded fast gas relay cards.



June 24, 2025 - EEA Level 1 Event

The BA had several energy imports (purchases) curtailed by the RC. The BA had a total loss of schedule(s) of 195 MW for HE 1800.

Outages included 344 MW (long term 138 MW due to equipment failure(s), short term 206 MW due to routine maintenance and/or flooding conditions).

Derates included 88 MW (long term 32 MW due to equipment failure(s), short term 56 MW due to an ongoing real-time contingency).

All the stated outages and derates were hydro generation.

The BA attempted to make a real-time purchase to no avail. They were told that purchase would be curtailed also. Exports from a local BA were curtailed, which helped to recover Area Control Error (ACE) and maintain reserves.

August 20, 2025 - EEA Level 3 Event

High humidity greatly reduced cooling tower(s) capacity and high temperatures reduced gas turbine outputs at several of the BA's gas plants. The wind forecast was forecasting more wind power at this time, but it did not show up. A 150 MW converter station was not in commercial service and was only available for emergency use.

The BA cut export sales which immediately restored required operating reserves. There was no load shed during this event.

August 27, 2025 - EEA Level 1 Event

High ambient temperature and wind generation coming in lower than forecast led to the entity declaring an EEA level 1. A transmission outage was limiting imports and there were forced outages on two generating units. A 75 MW generator unit was brought online to help improve conditions. No load was shed during this event.



Appendix D: Generating Availability Details

Generator unavailability can have a substantial impact on power grid reliability. Useful metrics for generator unavailability are EFOR and WEFOR, which measure unavailability of generators as a percentage of all calendar hours.

For the MRO region, the historical annual conventional generator WEFOR for all seasons is shown in Figure AD1 and solidifies the upward trend in WEFOR for the region. However, summers continue to be a point of low outage rates and stable performance in the region, as detailed in the sections below. The steep increase in 2022 WEFOR was driven in part by extreme outage events at the beginning (January and February) and end (December - Winter Storm Elliott) of the winter season as shown in figure AD2. This was also driven by high levels of outages in the fall due to simple cycle gas turbines and a small, but heavily MW weighted increase in WEFOR of fossil steam plants. Summers have been marked by low outage rates, with some marked decreases from the spring outage season. This effect is notable in 2025 due to the scale of WEFOR increases in spring and their continuation into June. This elevated rate is indeed driven largely by ongoing outages that started in the spring months.

Beginning with a slightly elevated WEFOR from a difficult 2022 fall maintenance season, performance throughout 2023 was poor due to a challenging winter with high unavailability among simple cycle gas turbines and poor fossil steam performance over the summer. WEFOR in 2024 and 2025 does not currently include any data from Canadian entities, making the data somewhat incomparable. However, 2024 data was largely in line with 2023, suggesting that issues around maintenance outage seasons and elevated forced outage rates are a continuing concern.

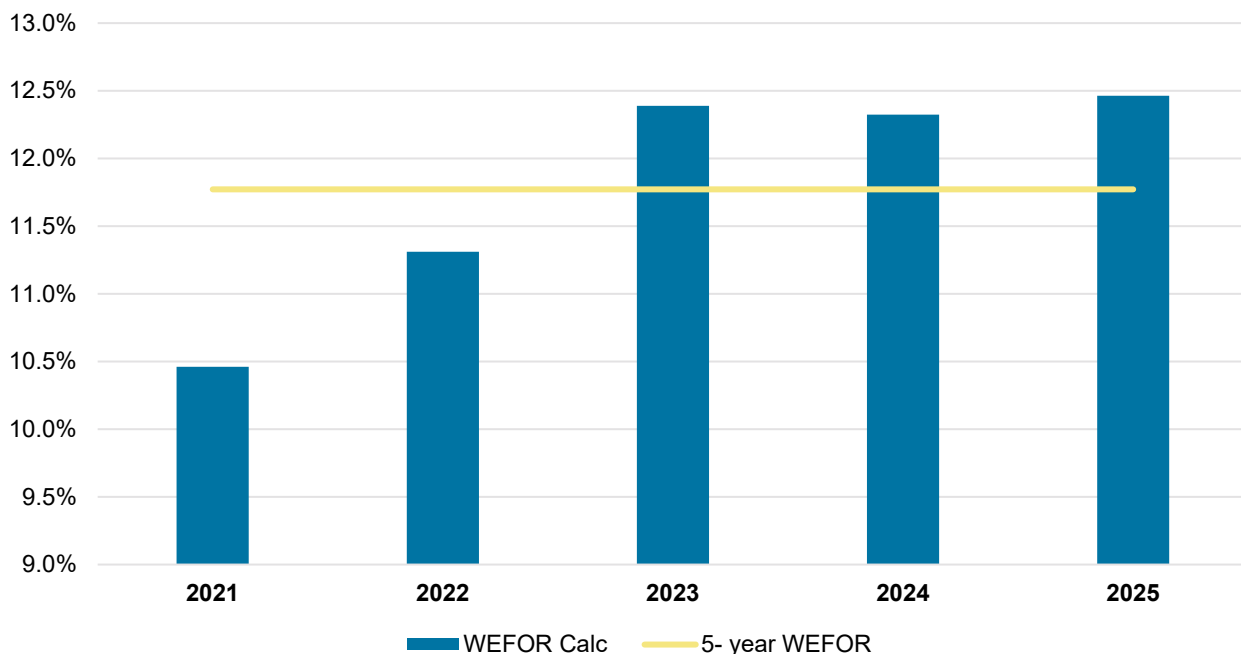


Figure AD1: MRO Annual Generator MW-Weighted EFOR



MRO WEFOR by Month 2021-2025

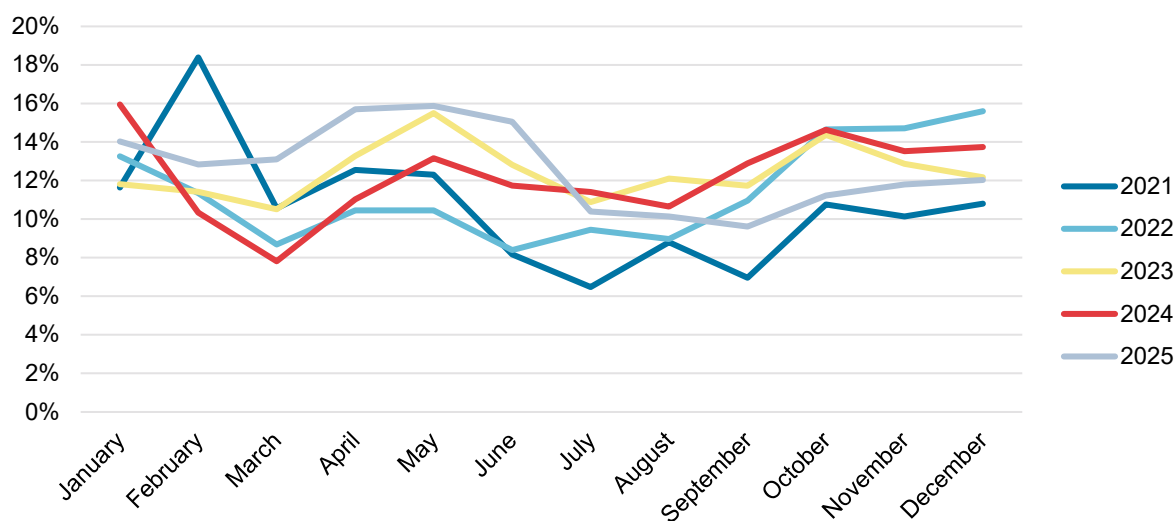


Figure AD2: MW-Weighted EFOR By Month

Table AD3 shows the top five causes for the 2025 summer season forced outages, forced derates, and startup failures by MWh loss for fossil-steam plants. Table AD4 shows the top outages in calendar year 2025 and Table AD5 shows this data for the previous five summer seasons.

Cause Type	Portion of Lost MWh
Generator Rotor – 2 events	7.4%
Waterwall – 30 events	7.3%
Operating Procedure Error – 5 events	7.0%
Generator Hydrogen Seals – 11 events	5.4%
Generator Vibration – 24 events	4.2%

Table AD3: Fossil-Steam 2025 Summer Outages

Cause Type	Portion of Lost MWh
Circulating Water Pipes – 3 events	6.6%
Generator Hydrogen Seals – 14 events	5.1%
Waterwall – 55 events	4.8%
Main Transformer – 56 events	3.6%
Tornados – 1 event	3.3%

Table AD4: Fossil-Steam 2025 Calendar Year Outage Causes

Cause Type	Portion of Lost MWh
Generator Rotor – General – 3 events	4.5%
Waterwall (Furnace wall) – 103 events	4.3%
Main Transformer – 46 events	4.2%
LP Turbine Buckets or Blades – 18 events	2.8%
First Reheater Leaks – 52 events	2.7%

Table AD5: Fossil-Steam 2021-2025 Summer Outage Causes



Fossil-steam outage causes for the 2025 summer season skew the five-year trends with extremely high impact events lingering from other seasons, namely generator rotor issues. Waterwall is historically the most impactful and well-distributed outage amongst fossil-steam units and acts as a barometer of relative impact of cause codes. Operating procedure error's megawatt hours are attributable to two events of very high duration, while the remaining three were relatively small impact. While not significant in the scope of the five-year or annual analysis, it does draw attention to the need to continually invest in human performance efforts. Hydrogen seals and generator vibration are both prone to reasonably well-distributed outages across the fleet but are outliers in severity due to the sometimes catastrophic nature of the failure modes. While consequential for the season in which it occurred, it does not imply systemic risk outside of well-known operational concerns.

In the annual scope, fossil steam units are not dominated by any one cause code or grouping of cause codes. Rather, the increased WEFOR over fleet average is mostly defined by a wide variety of outage causes. Those that make up the top five are waterwall, which is a widespread and well-understood operation issue, and cause codes that are largely defined by high-duration, high-impact events for singular units. The generator category does amplify the outage rate issues endemic in the spring season, but dramatically improved summer performance in 2025.

Table AD6 shows the top five causes for the 2025 summer season forced outages, forced derates, and startup failures by MWh lost for simple cycle gas turbines. Table AD7 shows the same information for calendar year 2025 and AD8 shows the same for five-year historical summer period.

Cause Type	Portion of Lost MWh
GT Starting System – 19 events	9.6%
Expander Turbine Bearings – 3 events	7.6%
Other Jet Engine Low Pressure Turbine Problems – 4 events	5.9%
JE Engine Vibration – 4 events	4.8%
GT Boroscope Inspection – 4 events	4.4%

Table AD6: Simple Cycle Gas Turbine 2025 Summer Outages

Cause Type	Portion of Lost MWh
Lack of fuel: Contract or Tariff allows for interruption – 277 events	11.4%
GT Starting System – 51 events	8.1%
Expander Turbine Bearings – 1 event	5.9%
Other Jet Engine Low Pressure Turbine Problems – 5 events	3.8%
JE Engine Vibration – 5 events	3.5%

Table AD7: Simple Cycle Gas Turbine 2025 Calendar Year Outage Causes

Cause Type	Portion of Lost MWh
JE Engine Vibration – 25 events	11.4%
Main Transformer – 22 events	8.1%
Other Misc. Generator Problems – 36 events	5.9%
GT Boroscope Inspection – 7 events	3.8%
JE Hydraulic Oil System – 12 events	3.4%

Table AD8: Simple Cycle Gas Turbine 2021-2025 Summer Outage Causes



Simple-cycle gas turbines have struggled with substantially higher than fleet proportionality of both event impact and WEFOR in the MRO region, even in the summer. This is, in part, due to maintenance issues as evidenced by the generator class's large contribution to increased WEFOR in the spring and fall maintenance periods. The relatively low run times and somewhat frequent cycling contribute to their outage rates. However, it is somewhat expected from the economics of peaking simple cycle gas turbines. In the 2025 summer season, gas turbines performed consistently with five-year averages and lost most megawatt hours due to generator stator issues predating the summer season. Stator events were limited to two units, not broadly impacting the forced outage rate of the generator category. However, the category's WEFOR for 2025 was higher than the fleet average WEFOR for the year.

From an annual perspective, gas turbines' major concern continues to be fuel availability. For 2025, fuel availability no longer makes the top five causes in either the summer seasonal or five season horizons. However, it remains the top cause of unavailability for the generator category. Other top causes do not have a strong seasonal correlation. Additional historical five-year and five-year summer season forced outage, forced derate, and startup failure causes for other types of generation is provided below.

Cause Type	Portion of Lost MWh
Generator Stator – 2 events	60%
GT Load Shaft and Bearings – 2 events	8.1%
Station Service Startup Transformer – 2 events	6.8%
Other Circulating Water System Problems – 4 events	3.8%
Other Gas Turbine Inlet Air Problems – 8 events	2.7%

Table AD9: Combined Cycle Gas Turbine 2025 Summer Outages

Cause Type	Portion of Lost MWh
Generator Stator – 2 events	52.4%
HP Desuperheater – 2 events	4.8%
GT Load shaft and Bearings – 1 event	3.1%
Other Gas Turbine Inlet Air Problems – 4 events	3.0%
Inlet Air Vanes / Nozzles – 4 events	2.9%

Table AD10: Combined Cycle Gas Turbine 2025 Calendar Year Outage Causes

Cause Type	Portion of Lost MWh
Generator Stator – 3 events	17.9%
Main Transformer – 10 events	8.2%
Gas Turbine Vibration – 5 events	7.7%
Cold Reheat Steam Piping up to Boiler – 1 event	7.5%
GT Fuel Piping and Valves – 19 events	5.7%

Table AD11: Combined Cycle Gas Turbine 2021-2025 Summer Outage Causes

Cause Type	Portion of Lost MWh
Retaining Rings – 1 event	53.2%
Station Service Startup Transformer – 1 event	10%
Turbine Lube Oil Pump – 6 events	7.6%
Other Feedwater System Problems – 2 events	3.1%
Other Circulating Water System Problems – 2 events	3.1%

Table AD12: Combined Cycle Steam 2025 Summer Outages



Cause Type	Portion of Lost MWh
Retaining Rings – 1 event	42.1%
HP Desuperheater/Attemperator Piping – 2 events	5.3%
Turbine Lube Oil Pumps – 3 events	5.2%
Station Service Startup Transformer – 1 event	3.5%
Open Cooling Water Heat Exchangers – 1 event	3.4%

Table AD13: Combined Cycle Steam 2025 Calendar Year Outage Causes

Cause Type	Portion of Lost MWh
Generator Stator – 2 events	11.7%
Boiler, Misc. – 16 events	8.0%
Main Transformer – 7 events	5.3%
Gas Turbine Vibration – 3 events	5.0%
Exciter Commutator and Brushes – 7 events	4.7%

Table AD14: Combined Cycle Steam 2021-2025 Summer Outage Cause

Appendix E: Transmission Availability Details

Table AE1 shows the number of circuits and circuit miles for overhead 100-599kV AC transmission lines within the MRO region. AC circuits in the voltage range of 100-399kV accounted for 90% of the outages during the latest summer season and will be the elements analyzed in the section below.

100-199kV		200-299kV		300-399kV		400-599kV	
Circuits	Miles	Circuits	Miles	Circuits	Miles	Circuits	Miles
3,557	48,322	429	14,359	535	18,878	9	1,001

Table AE1: AC Transmission Circuit Miles

Figure AE2 shows the number of 100kV and above automatic AC circuit outages that include both momentary (for 200kV and above) and sustained outages for the 2021 through 2025 summer seasons. There were a total of 502 outages reported for the 2025 summer season for the 100-399kV voltage classes. There were no 400-599kV outages reported for the summer of 2025.

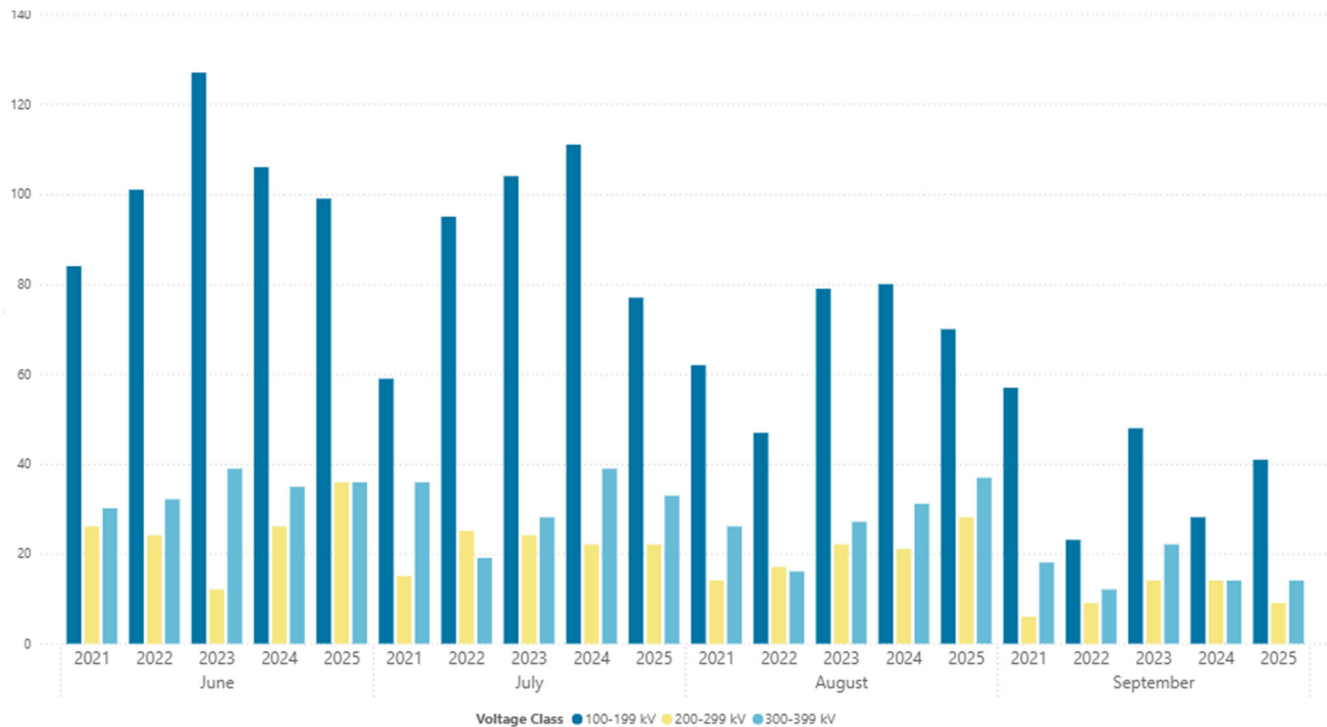


Figure AE2: Summer Automatic Outages by Month



Figure AE3 shows the causes of momentary outages for the past five summer seasons. The causes are in descending order for the total number of momentary outages over the five-year period. The chart does not include momentary automatic outages for circuits 100-199kV because causes are not reported for momentary outages on circuits less than 200kV. Lightning was the leading cause of momentary outages for the summer season of 2025 with 30, followed by unknown with 21 and weather, excluding lightning with 15 reported outages.

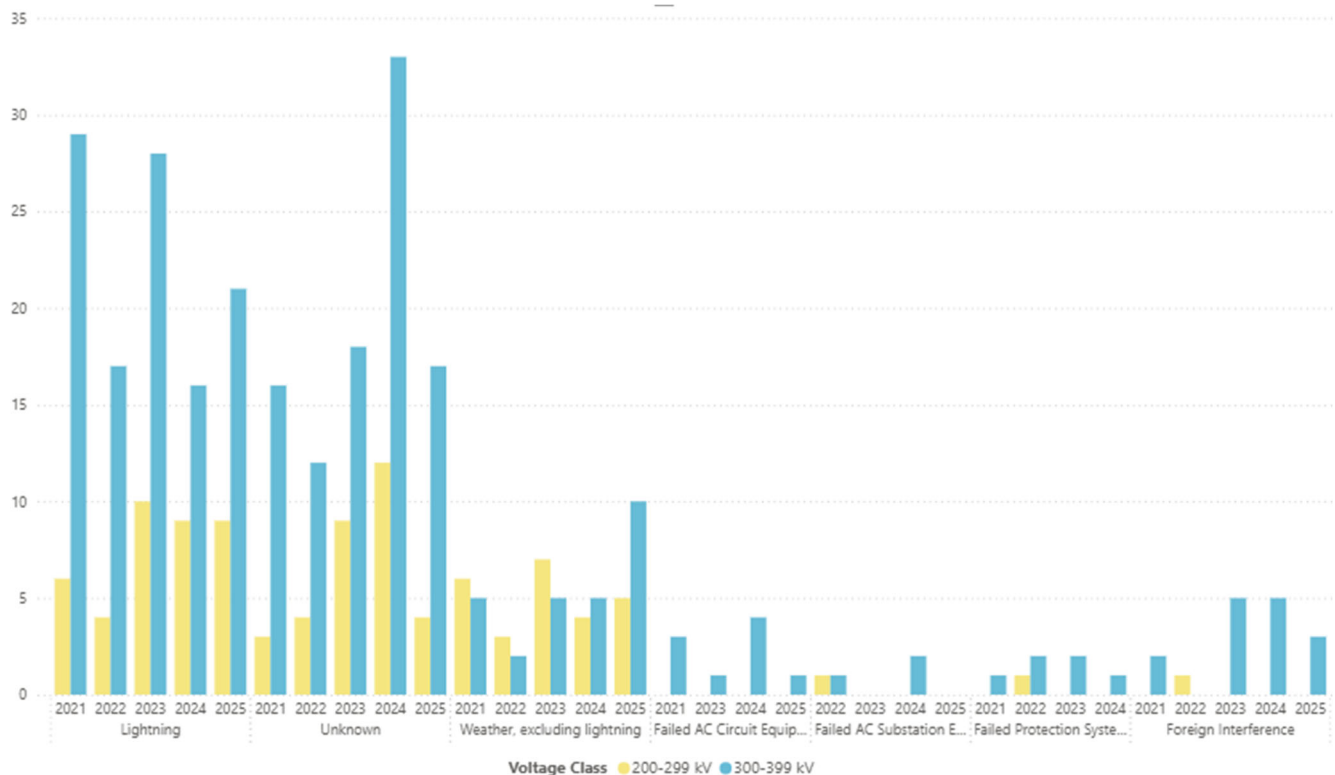


Figure AE3: Summer Momentary Outages by Cause

Figure AE4 shows the causes of sustained outages (automatic outages with an outage duration of a minute or greater) for the 2021 through 2025 summer seasons. The causes are in descending order for the total number of sustained outages over the five-year period. The chart shows that failed AC circuit equipment, other, and failed AC substation equipment continue to be major contributors to sustained outages during the summer seasons. For the most recent period, failed AC circuit equipment was the largest contributor to sustained outages with 102. Followed by other with 99, and failed AC substation equipment with 77.



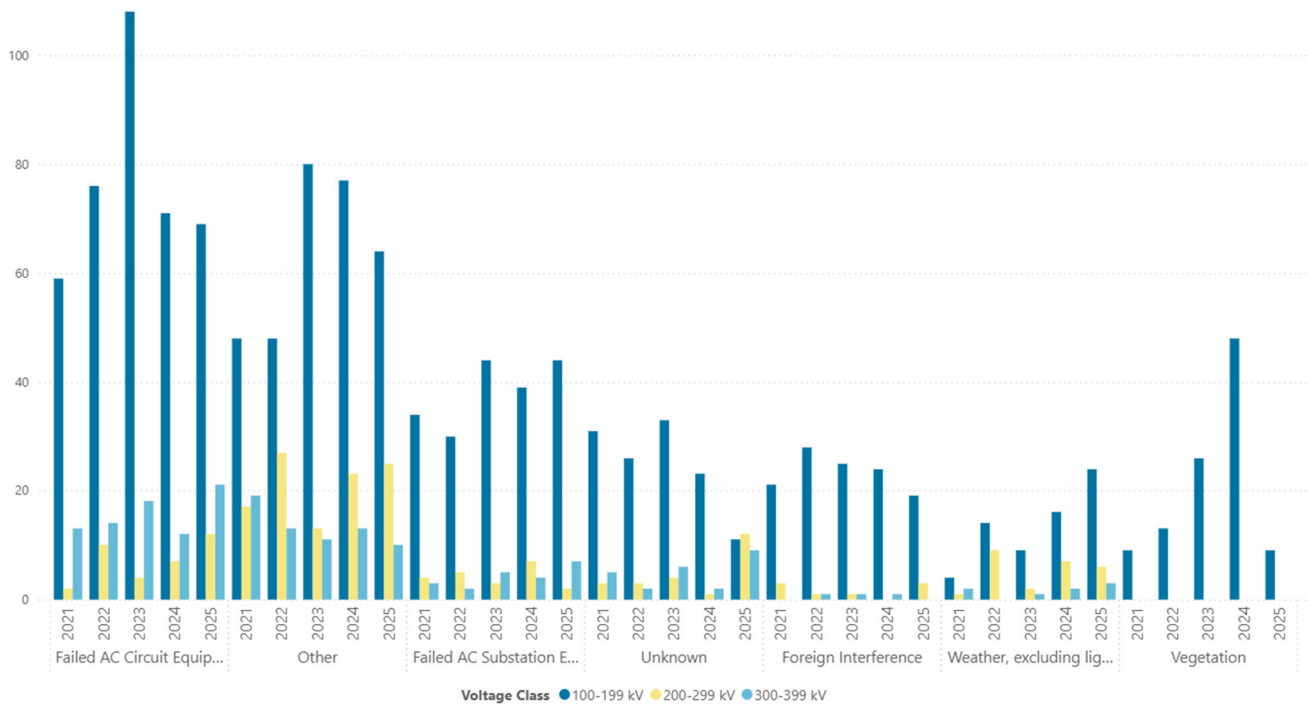


Figure AE4: Summer Sustained Outages by Cause

Figure AE5 reflects the yearly summer total outages per 100 circuit miles for 100-399kV circuits. The chart shows the outages per 100 circuit miles for the 100-199kV voltage class continue to decrease while the 200-299 and 300-399kV voltage class outages continue to increase (since 2023).

June 19, 2025, had the largest number of outages reported in a single day with 3.8% of the 2025 summer season. The three-day period of August 8-10, 2025, had 6.5% of the outages as two storms travel across the southern portion of the MRO footprint.

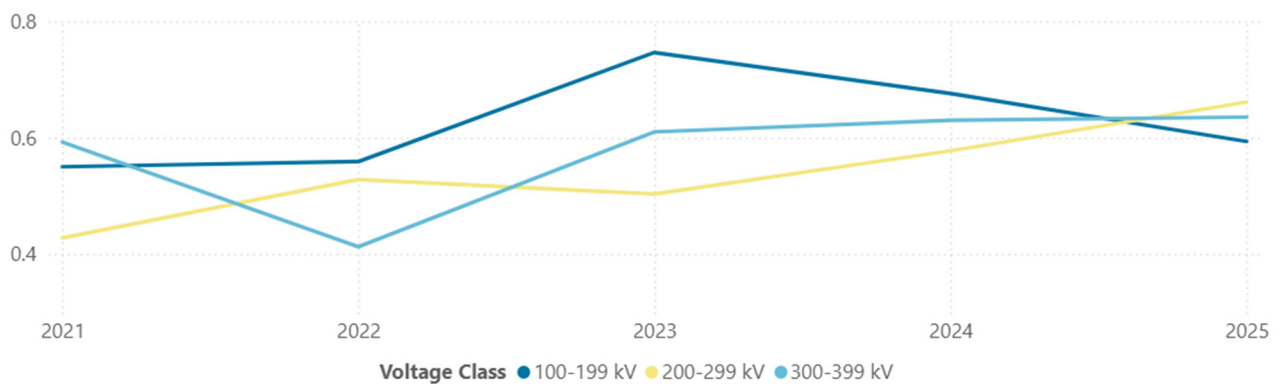


Figure AE5: Total Transmission Outages per 100 Circuit Miles



GLOSSARY

Compliance	Compliance by industry is conforming to Reliability Standards. Strategies by MRO to achieve industry compliance range from education to enforcement and/or sanctions
Bulk Power System	Facilities and control systems necessary for operating an interconnected electric generation and transmission network (or any portion thereof); and electric power needed to maintain transmission system reliability and serve load. The term does not include facilities used in the local distribution of electric energy.
CMEP	The rules governing compliance and enforcement oversight are included in the Compliance Monitoring and Enforcement Program.
Eastern Interconnection	The Eastern Interconnection is a major bulk power system grid in North America. All the electric utilities in the Eastern Interconnection are electrically tied together during normal system conditions and operate at a synchronized frequency that averages 60 Hz. The Eastern Interconnection reaches from central Canada eastward to the Atlantic coast (excluding Quebec) south to Florida and back west to the foot of the Rockies (excluding most of Texas).
Highly Reliable Organization	An organization that avoids sudden, uncontrolled cascading events despite operating in a highly complex environment by adopting a constant state of vigilance resulting in the fewest number of operating errors. These organizations have the following characteristics: Preoccupation with failure • Attention on “close calls” and “near misses” Reluctance to simplify interpretations • Solid “root cause” analysis practices Sensitivity to operations • Situational awareness and carefully designed change management processes Commitment to resilience • Resources are continually devoted to corrective action plans and training Deference to expertise • Listens to experts on the front lines (ex. authorities follows expertise) Refer to Managing the Unexpected-Assuring High Performance in an Age of Complexity by Karl E. Weick and Kathleen M. Sutcliffe
Industry	Those regulated by MRO include: Investor-owned utilities MRO’s Regulatory Philosophy Cooperative and municipal utilities Canadian utilities Transmission operators • Generator operators



	U.S. federal power agencies Other users, owners, and operators, of the bulk power system For more information, please refer to the MRO registry (known as “Registered Entities”)
Industry Stakeholders	A person, group or organization that has interest or concern in the industry and MRO
Intelligence-Led	Using intelligence products based on analytics, root cause analysis, and other mechanisms to inform program areas, such as compliance, around risks.
Registered Entity	An owner, user, or operator who has a material impact on the bulk power system and is on the registry
Reliable Operations	Operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.
Responsive Regulation	Responsive regulation is an approach that varies the compliance oversight and enforcement response depending on the registered entity’s individual circumstances. Circumstances that are considered include the participant’s compliance history, function, location, cooperation, and other factors. The aim of the responsive regulators is to return the registered entity to full voluntary compliance. The response is therefore proportional to the risks and consistent for the same type of registered entity in similar circumstances.
Risk	The chance of something happening has the potential to have an adverse impact on bulk power system reliability. All risks are considered in the context of the potential adverse outcome.



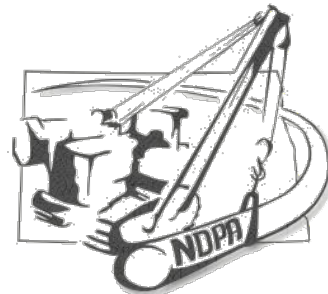
North Dakota Industrial Commission

Justin J. Kringstad

Geological Engineer

Director

North Dakota Pipeline Authority



August 25, 2026

Over 100 Years...

A Story of Energy, Innovation, and Opportunity on the Northern Plains

PROCLAMATION



Whereas Natural Gas will be in the gas mains of Glendive, Montana, Saturday, July 31, 1926, and

Whereas the City of Glendive is desirous of cooperating with the Montana-Dakota Power Company in the advertising campaign which will bring Glendive before the people of the United States so that they may know the opportunities and commercial advantages offered by the Gate City with its abundant supply of natural gas.

Now therefore I, M. G. Danskin, as mayor of the city of Glendive, Montana, do hereby declare and order to be set aside Saturday, the 31st day of July, A. D. 1926, to be known as "Natural Gas Day," and do hereby urge all citizens and organizations interested in the welfare of this community to join in celebrating "Natural Gas Day" in Glendive.

Issued this 22nd day of July, A. D. 1926.

M. G. DANSKIN,
Mayor of Glendive.



BIG THREE-DAY CELEBRATION

THURSDAY
July 29

FRIDAY
July 30

SATURDAY
July 31

Municipal Swimming Pool--Glendive, Montana
WATER CARNIVAL AND BATHING BEAUTY CONTEST EACH EVENING

Swimming and Diving Contests

Water Novelty Events

Games and amusements on the Carnival Midway

SATURDAY, OFFICIALLY DESIGNATED
GAS DAY

The Swimming Pool and City Park will be illuminated by Natural Gas, and at the close of the ceremonies the winner of the Bathing Beauty Contest will be crowned Miss Eastern Montana by Mayor M. G. Danskin.

Celebrate With Us

CIVIC ORGANIZATIONS OF GLENDDIVE

After Two Million Years...

A GIANT AWAKENS

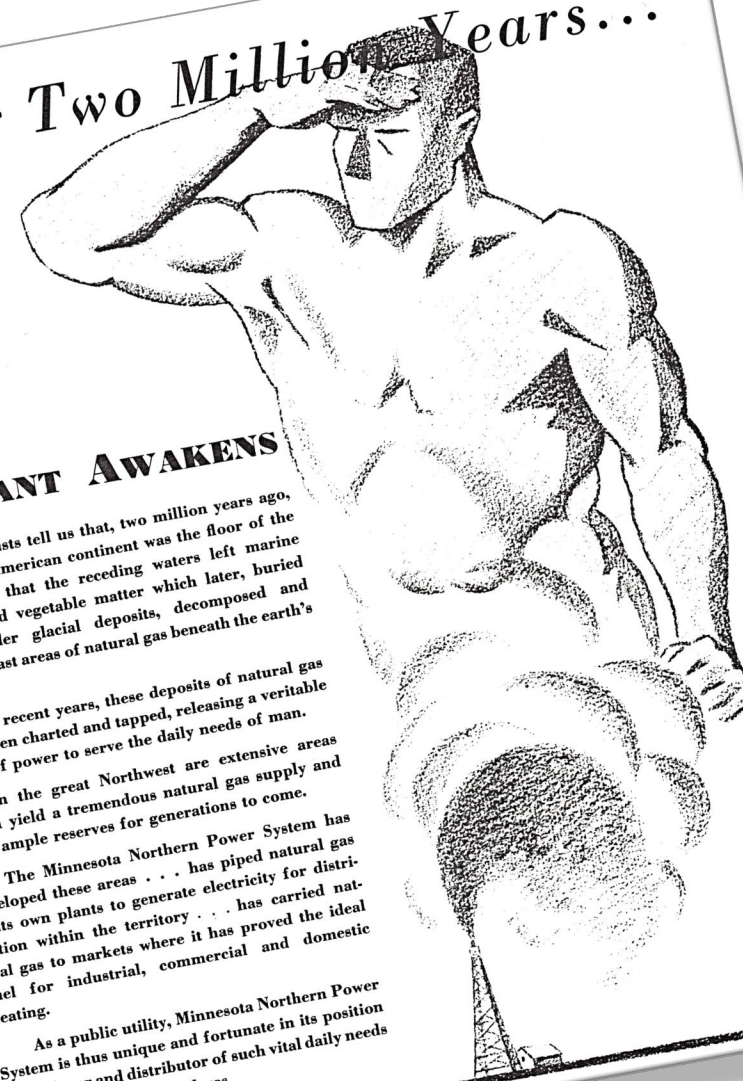
Geologists tell us that, two million years ago, the North American continent was the floor of the ocean and that the receding waters left marine animal and vegetable matter which later, buried deep under glacial deposits, decomposed and formed vast areas of natural gas beneath the earth's surface.

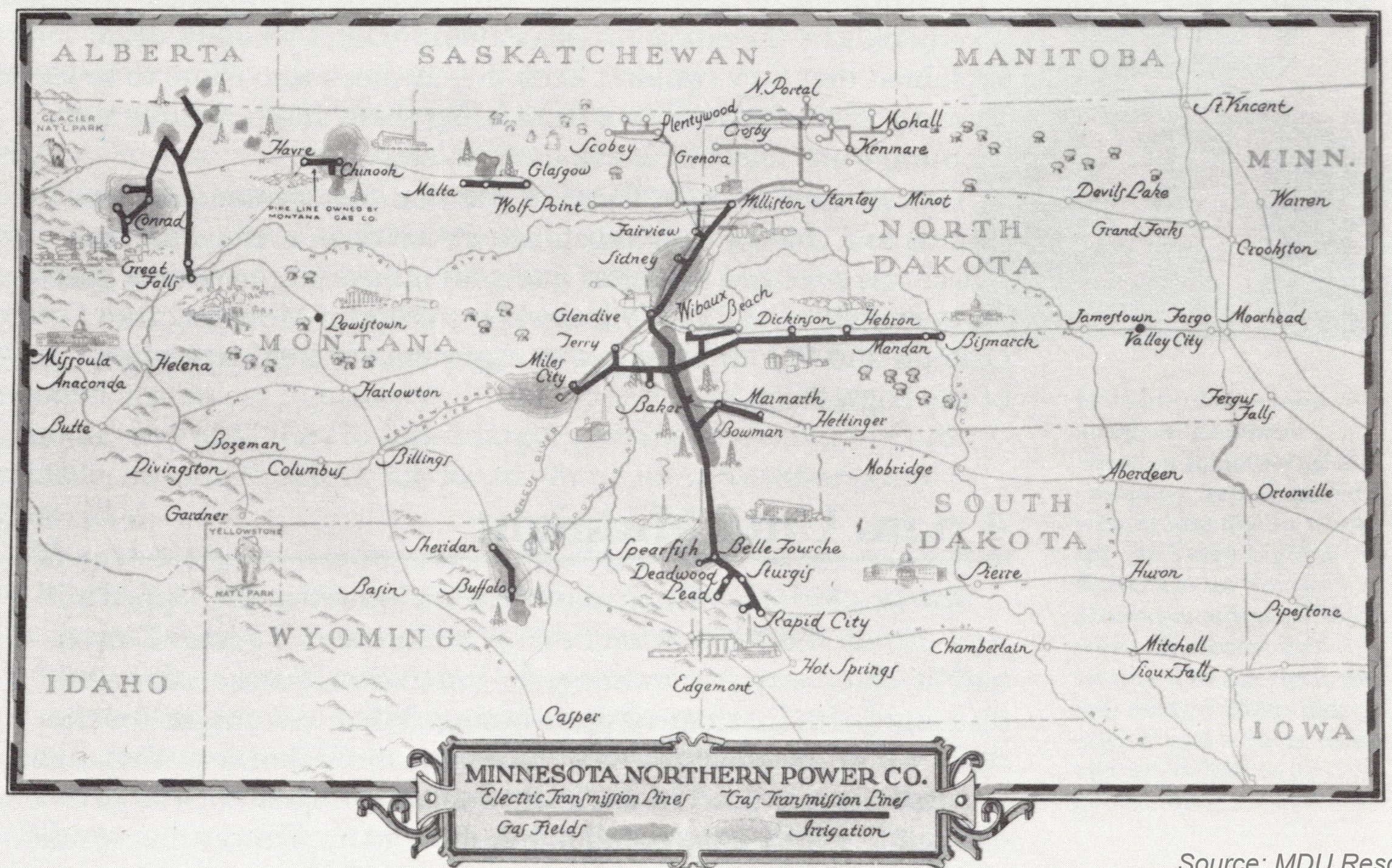
Of recent years, these deposits of natural gas have been charted and tapped, releasing a veritable giant of power to serve the daily needs of man.

In the great Northwest are extensive areas which yield a tremendous natural gas supply and hold ample reserves for generations to come.

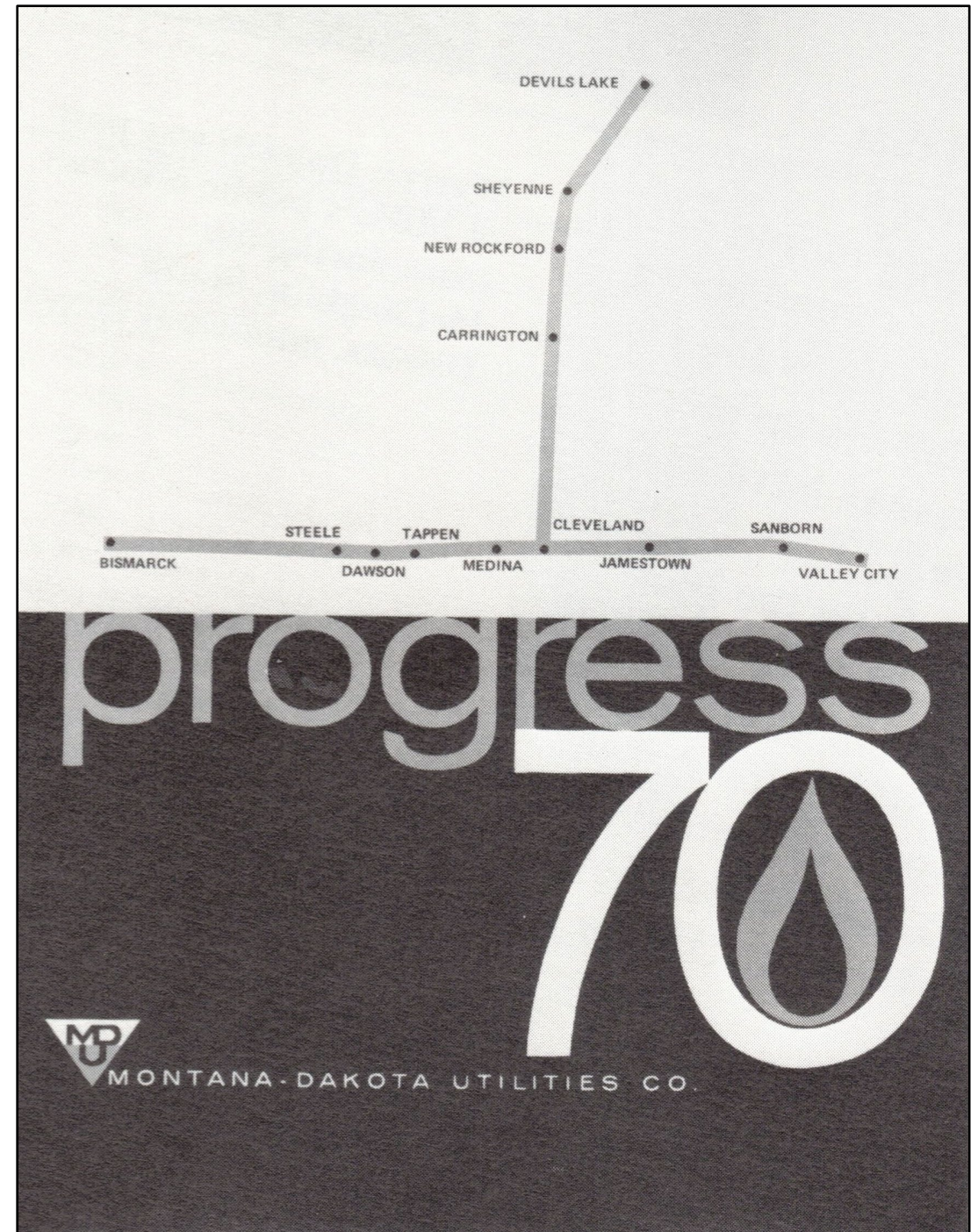
The Minnesota Northern Power System has developed these areas . . . has piped natural gas to its own plants to generate electricity for distribution within the territory . . . has carried natural gas to markets where it has proved the ideal fuel for industrial, commercial and domestic heating.

As a public utility, Minnesota Northern Power System is thus unique and fortunate in its position as producer and distributor of such vital daily needs as electricity and natural gas.





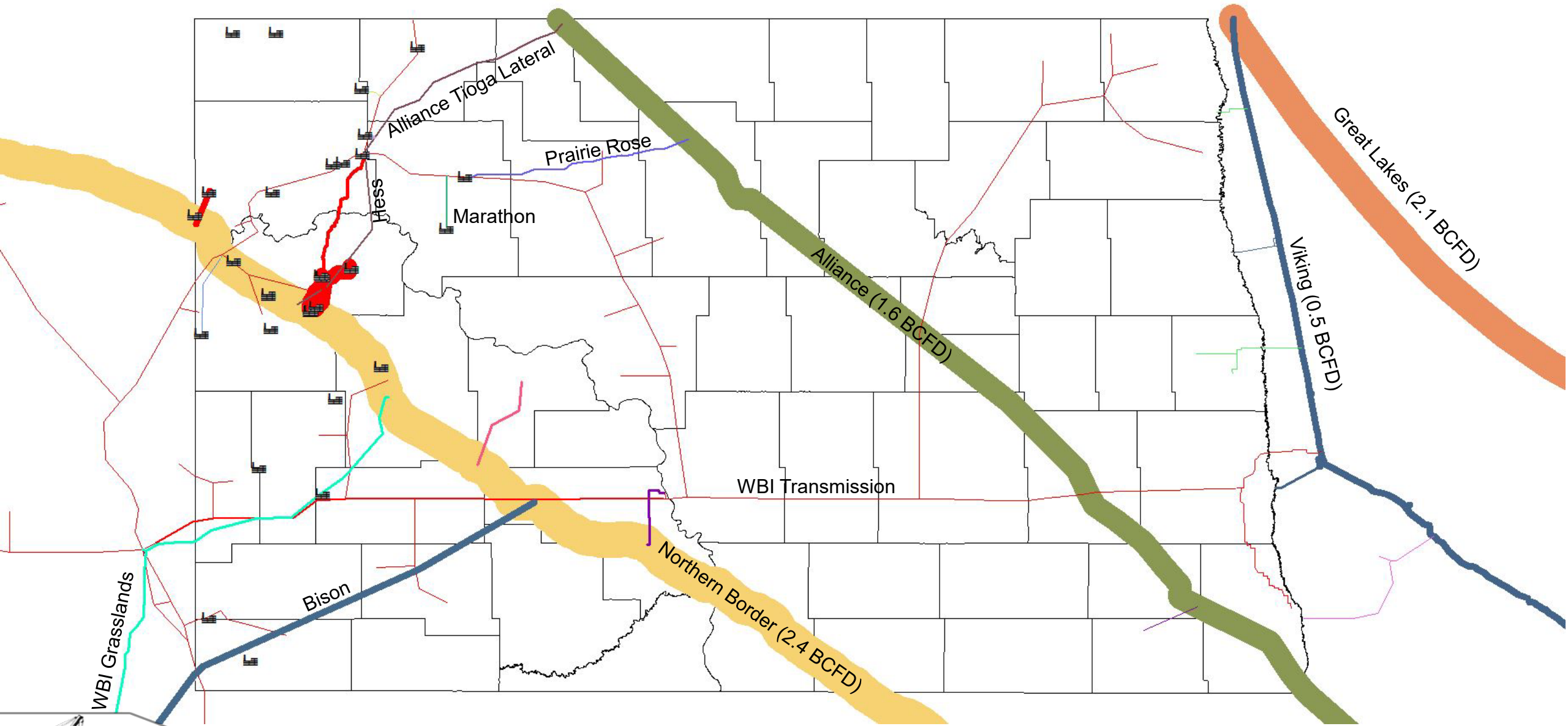
The first pipeline push to eastern North Dakota



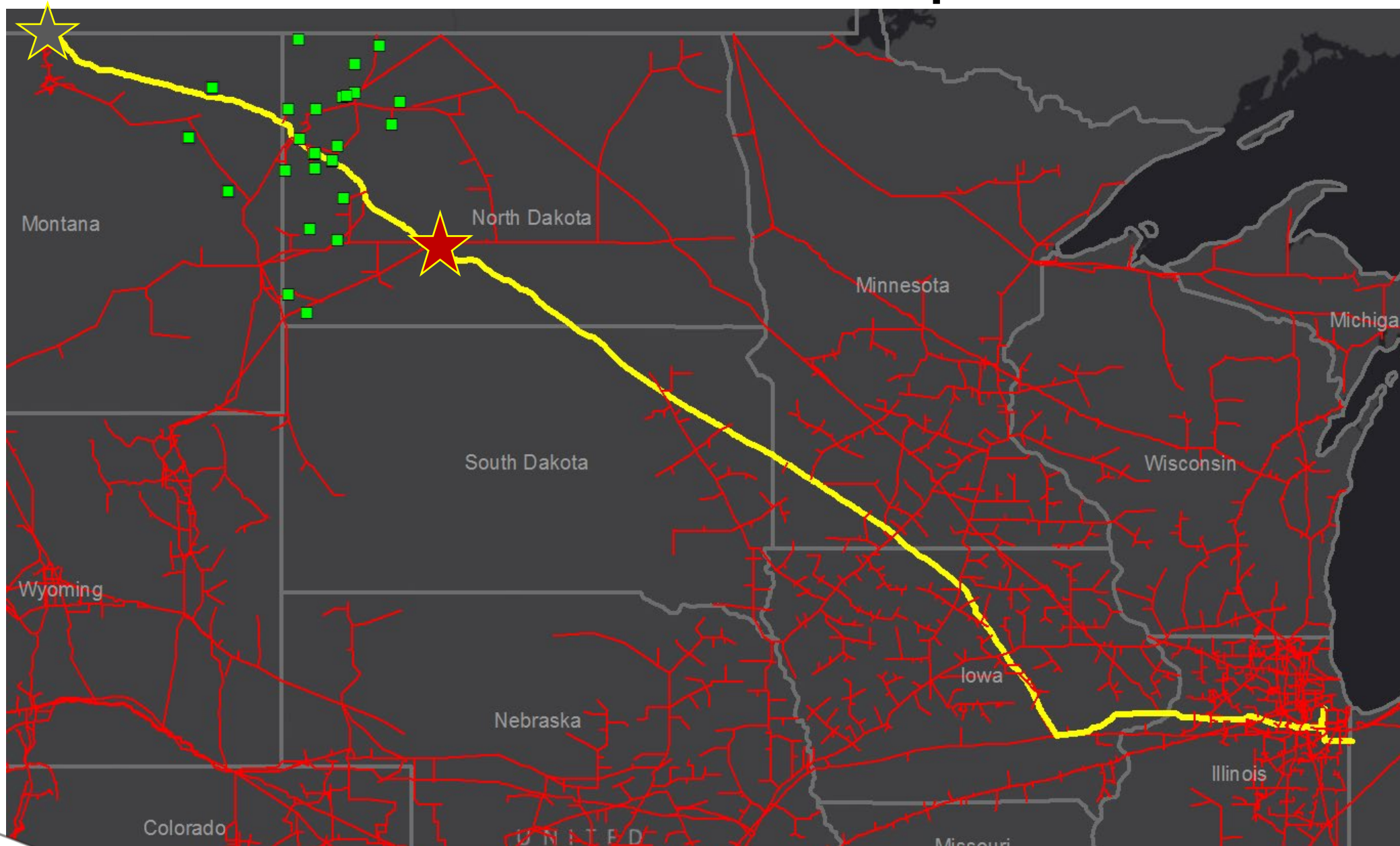
Source: MDU Resources

The modern era...

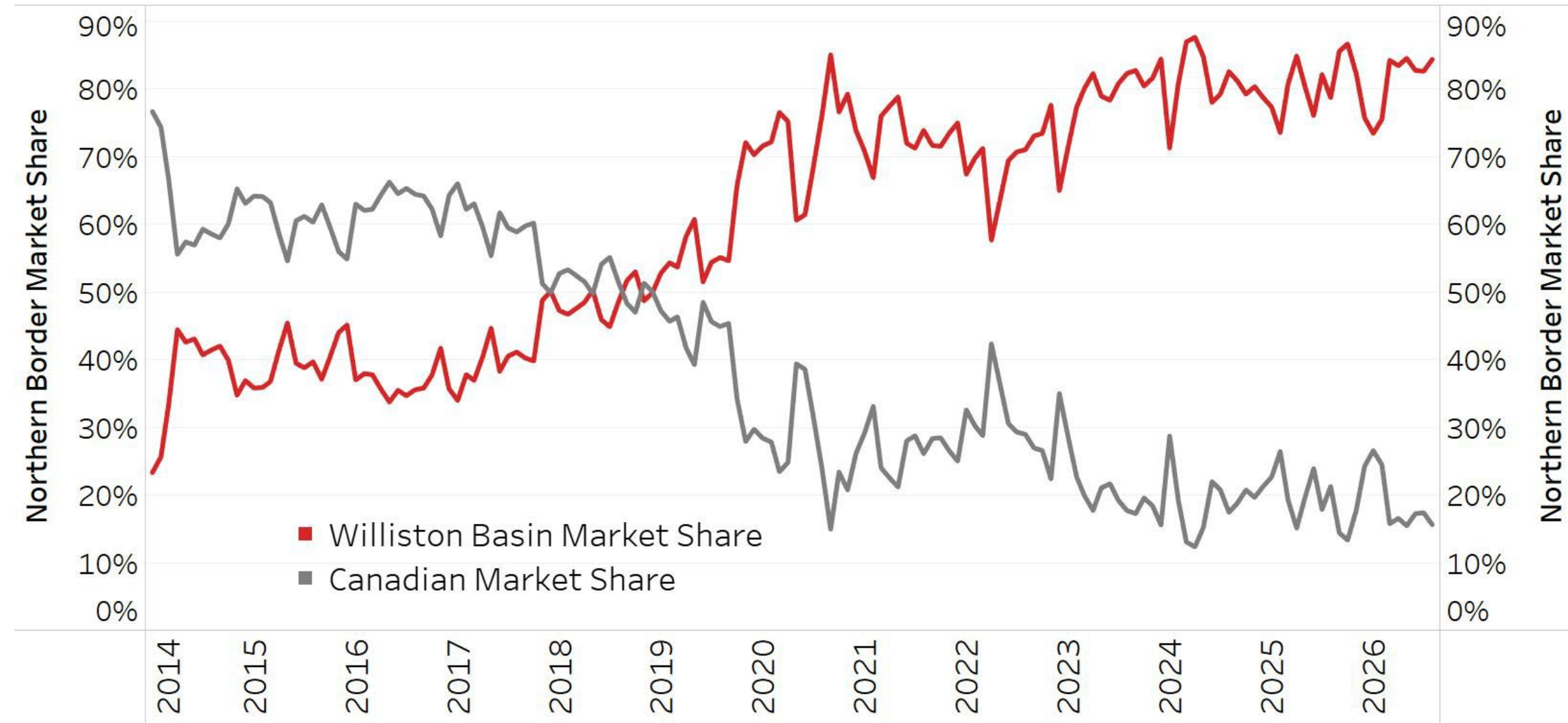
Residue Gas Pipeline Capacity Visualization



Northern Border Pipeline



Northern Border Pipeline Market Share



■ Williston Basin Market Share
■ Canadian Market Share



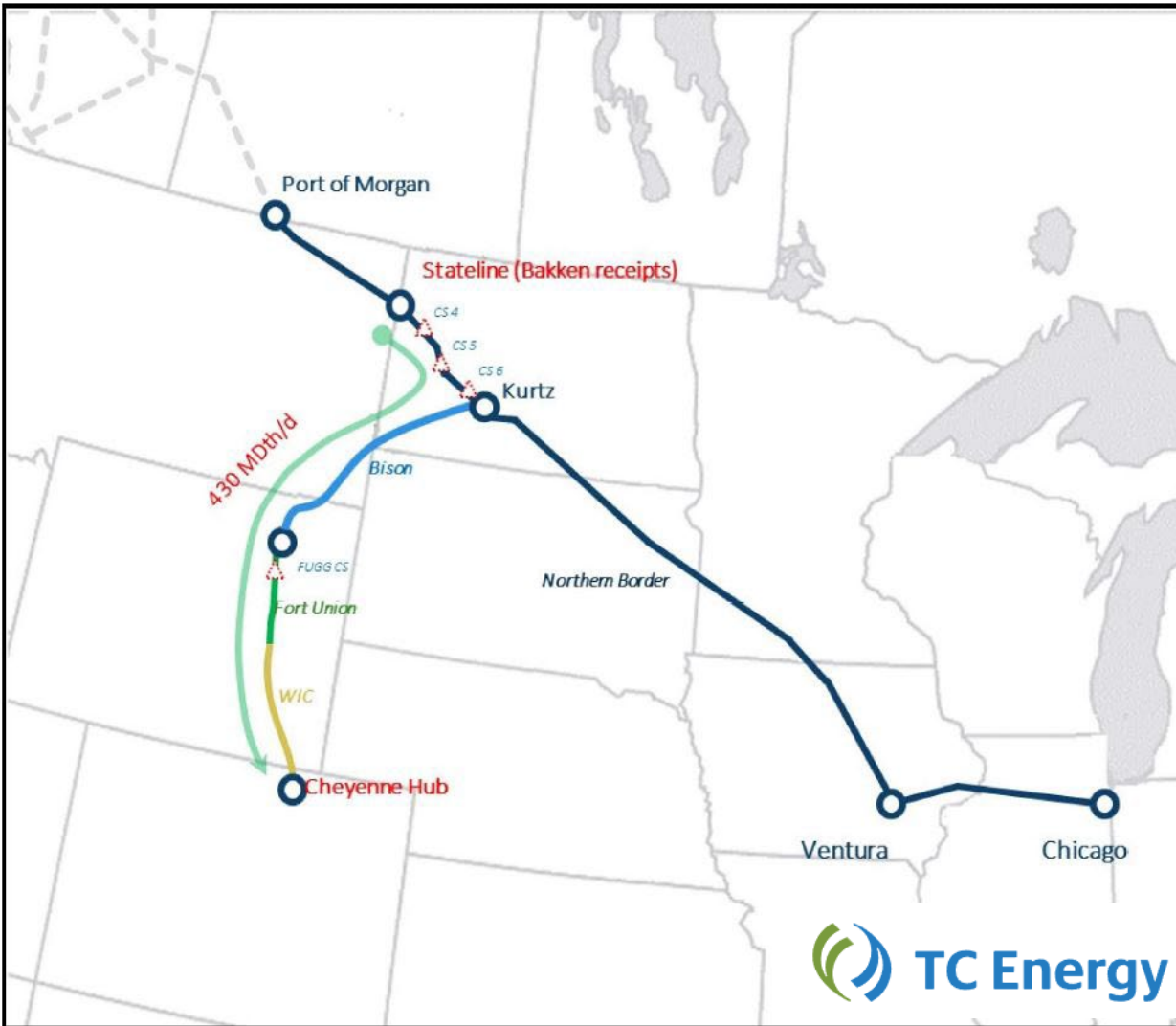
TC Energy / Kinder Morgan: Bakken xPress Project

Project Highlights

- Non-binding open season April 4 - May 6, 2022
- Binding Open Season: June 1-30, 2023
- Three compressor upgrades in North Dakota
- Reverse the idle Bison Pipeline (30" – 302 Mile)
- Capacity 300,000 Dth/Day (430,000 Offered)
- May 2026 targeted in-service date **(DELAYED)**
- Fort Union Gas Gathering and Wyoming Interstate Company provide further transport to Cheyenne hub.
- Seeking commitments 10yrs or Longer
- \$555 million: \$347 Replacement/\$208 Expansion

Proposed Rates

- NBPL/Bison \$0.45/Dth + Fuel/Elec to WIC/FUG Interconnect
- WIC/FUG to Cheyenne \$0.30/Dth + Fuel/Elec



Options Beyond 2026: The 5 “C’s”

Construction (Interstate)

- Long-haul Pipe to New or Expanded Markets

Compete

- Price Canadian Volumes to Flow Elsewhere

Compression

- Increase Capacity on Existing Interstate Systems

Consumption

- Intra Region Gas Demand Expansion

Contraction

- Reduce E&P Activity to Meet Limited Gas Options



Options Beyond 2026: The 5 “C’s”

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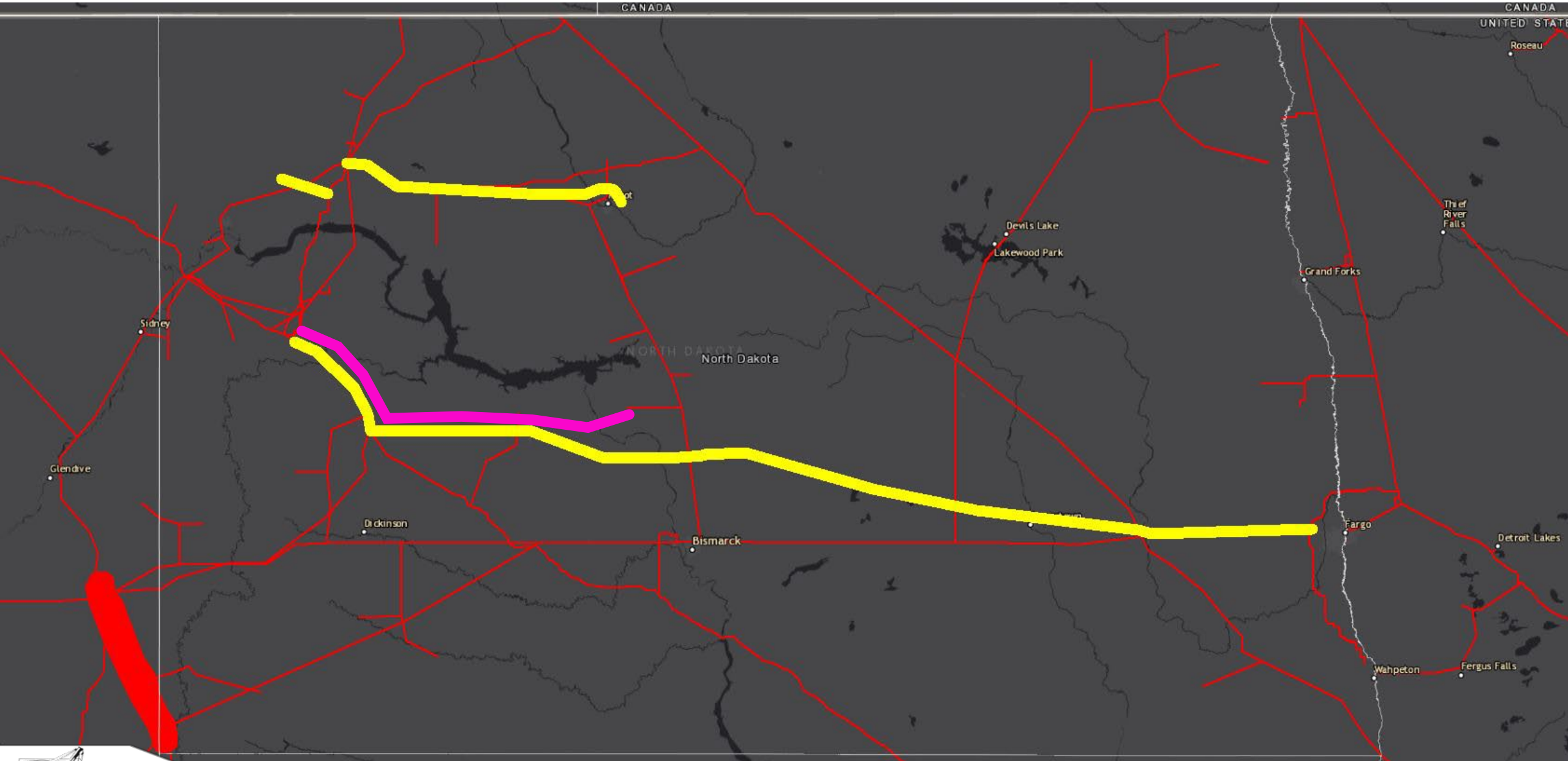
- Intra Region Gas Demand Expansion

Contraction

- Reduce E&P Activity to Meet Limited Gas Options



Beyond 2026: Gas Transmission Projects



Beyond 2026: Gas Transmission Projects

Minot Industrial Pipeline

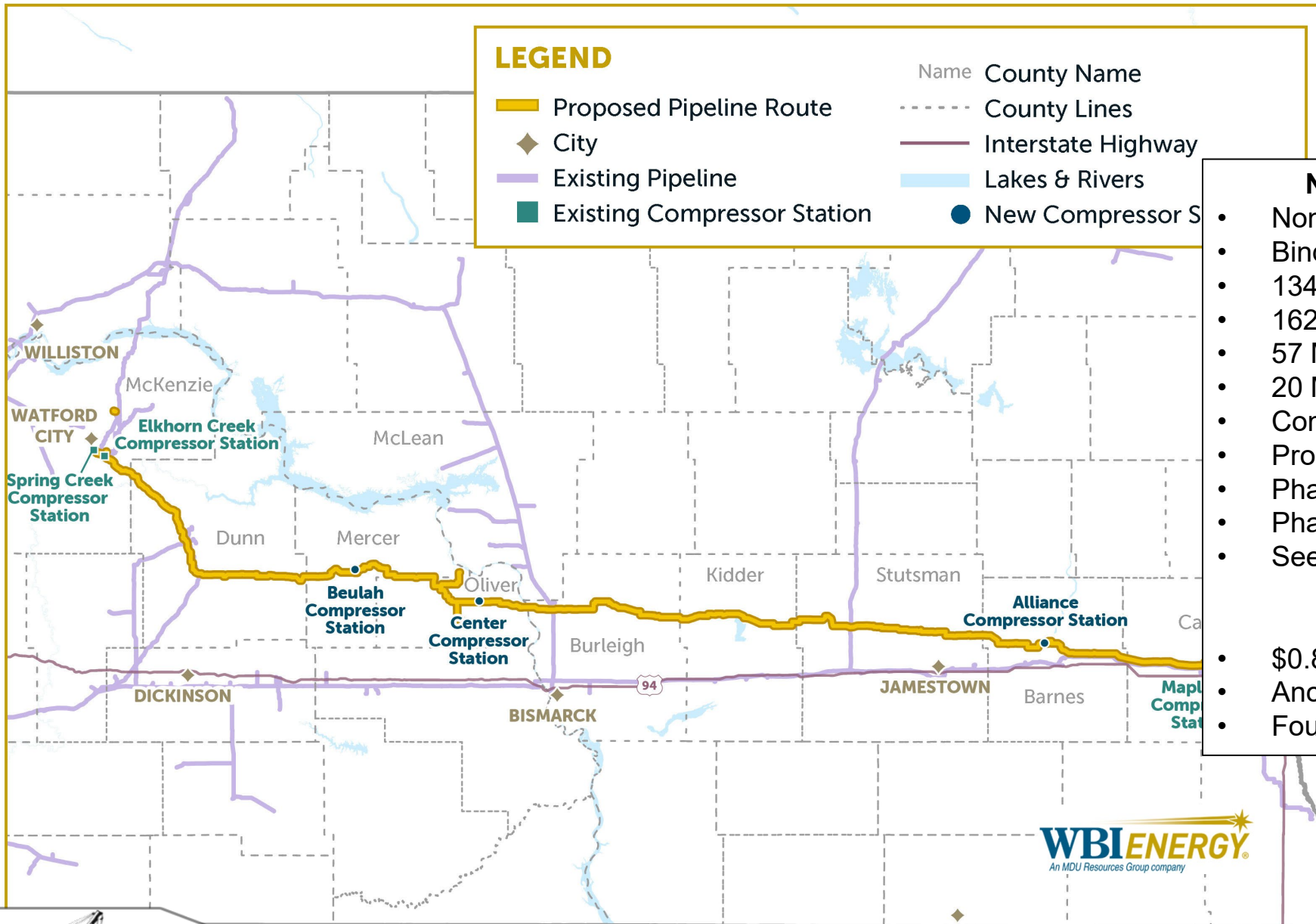
- Developer: WBI Energy Transmission
- Status: Under development
- 20" – 87 miles
- Capacity 250,000 MCFD
- Q4 2029 targeted in-service date

Line Section 32 Expansion

- Developer: WBI Energy Transmission
- Status: Under development
- 24" – 17 miles
- Capacity 200,000 MCFD
- Q4 2028 targeted in-service date



WBI Energy: Proposed Bakken East Project



Natural Gas Pipeline Project Highlights

- Non-binding open season Dec 16 – Jan 31, 2025
- Binding open season Feb 2 – Mar 12, 2026
- 134 Miles: 42" Pipe
- 162 Miles: 36" Pipe
- 57 Miles: 30" Pipe
- 20 Miles: 20"-30" Pipe (Laterals)
- Compression: ~89,000 HP
- Proposed Capacity 1,400,000 to 1,700,000 Dth/Day
- Phase 1 (West) : Nov 2029 targeted in-service
- Phase 2 (East) : Nov 2030 targeted in-service
- Seeking commitments 20yrs or Longer

Estimated Rates

- \$0.85 to \$0.90/Dth + Fuel/Electric/Commodity
- Anchor Shipper Minimum: 100,000 Dth/Day
- Foundation Shipper Minimum: 250,000 Dth/Day



Intensity Infrastructure Partners Proposed Pipeline



Phase 1 Project Highlights

- Non-binding open season Feb 3 – Mar 7, 2025
- 136 Miles: 36" Pipe
- Proposed Capacity 1,100,000 Dth/Day
- July 2029 targeted in-service
- Seeking commitments 10yrs or Longer

Phase 1 Estimated Rates

- Sub-\$0.40/Dth + Fuel/Electric/Commodity
- Anchor Shipper Minimum: 100,000 Dth/Day
- Foundation Shipper Minimum: 250,000 Dth/Day

Phase 2 Project Highlights

- Non-binding open season Apr 17 – May 23, 2025
- 208 Miles: 30" Pipe
- Proposed Capacity 430,000 Dth/Day
- January 2030 targeted in-service
- Seeking commitments 10yrs or Longer

Phase 2 Estimated Rates

- \$0.80/Dth + Fuel/Electric/Commodity
- Anchor Shipper Minimum: 100,000 Dth/Day
- Foundation Shipper Minimum: 250,000 Dth/Day



WBI Energy: Fourteen Open House Events

Five FERC Public Scoping Sessions

WBI Landowner Meetings

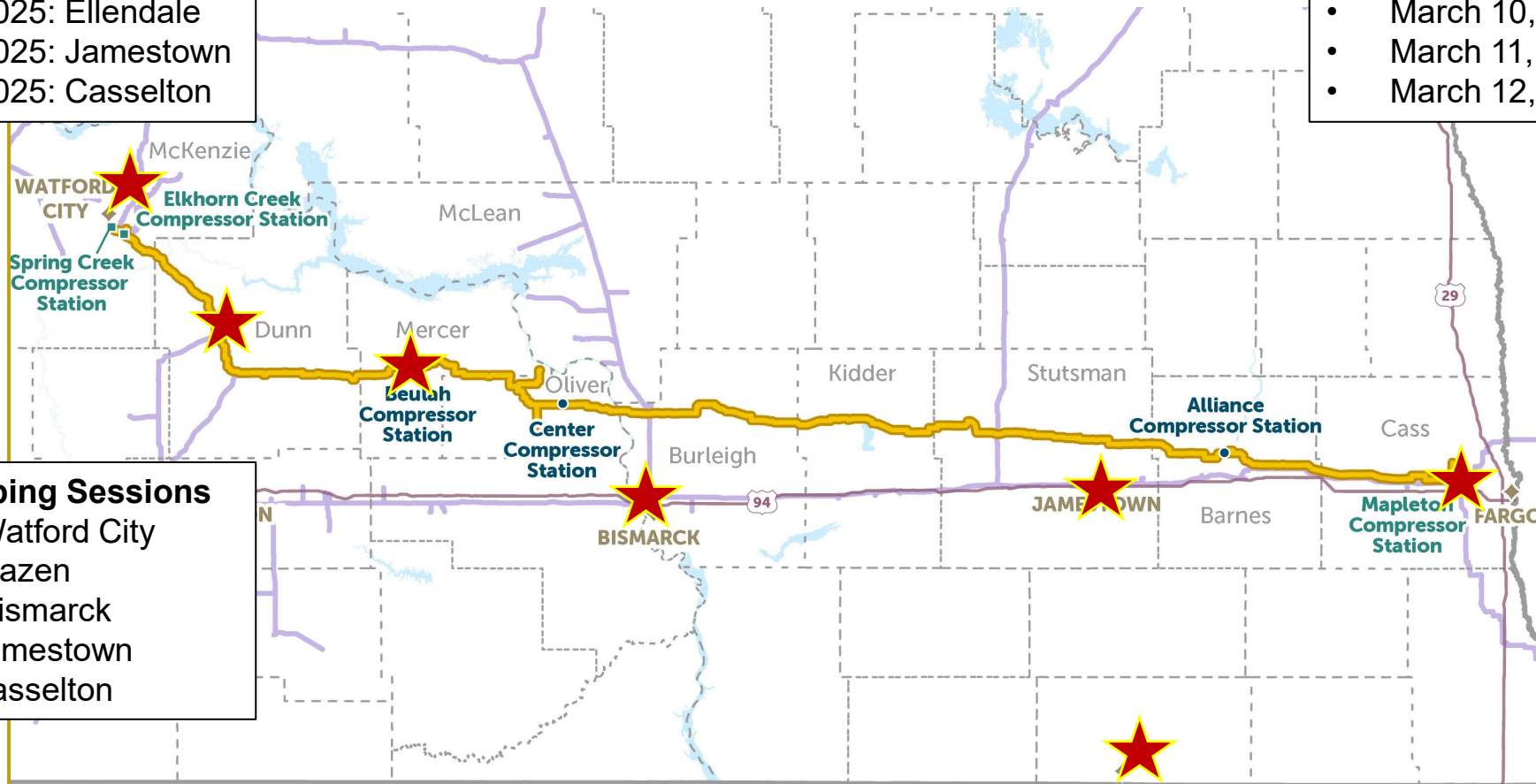
- November 3, 2025: Watford City
- November 4, 2025: Killdeer
- November 5, 2025: Beulah
- November 17, 2025: Bismarck
- November 18, 2025: Ellendale
- November 19, 2025: Jamestown
- November 20, 2025: Casselton

WBI Public Open Houses

- February 23, 2026: Casselton
- February 24, 2026: Ellendale
- February 25, 2026: Jamestown
- February 26, 2026: Bismarck
- March 10, 2026: Beulah
- March 11, 2026: Killdeer
- March 12, 2026: Watford City

FERC Public Scoping Sessions

- May 19, 2026: Watford City
- May 20, 2026: Hazen
- May 21, 2026: Bismarck
- June 2, 2026: Jamestown
- June 4, 2026: Casselton





Bakken East – Preliminary Work*

-97% permission to survey received for 350 mile mainline

- 80% permission to survey received for 25 miles of laterals

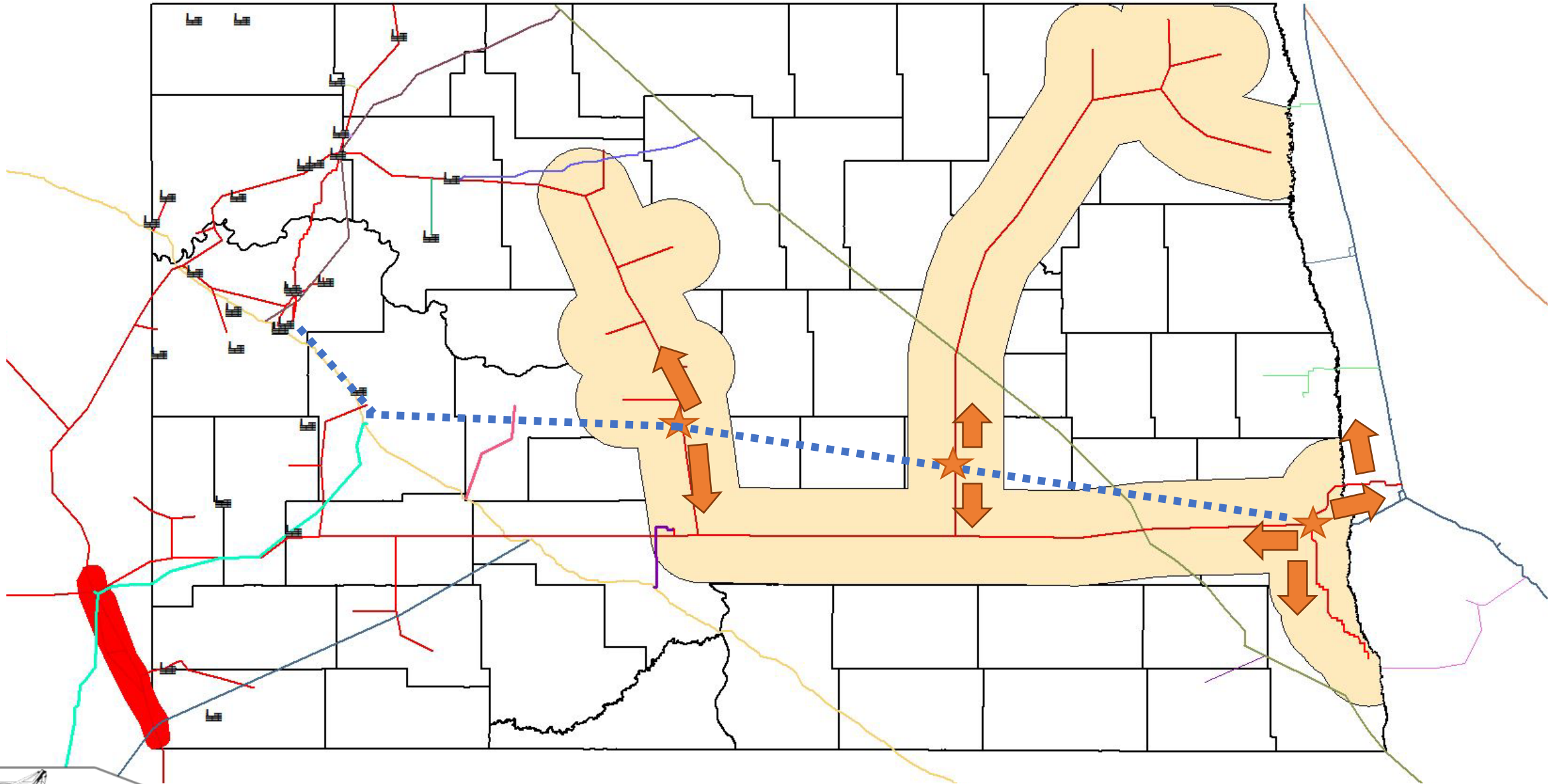
- 81% of wetland and general habitat surveys completed
- 40% of cultural surveys and staging yards completed
- 86% of special status species surveys completed

* Updated as of August 3, 2026

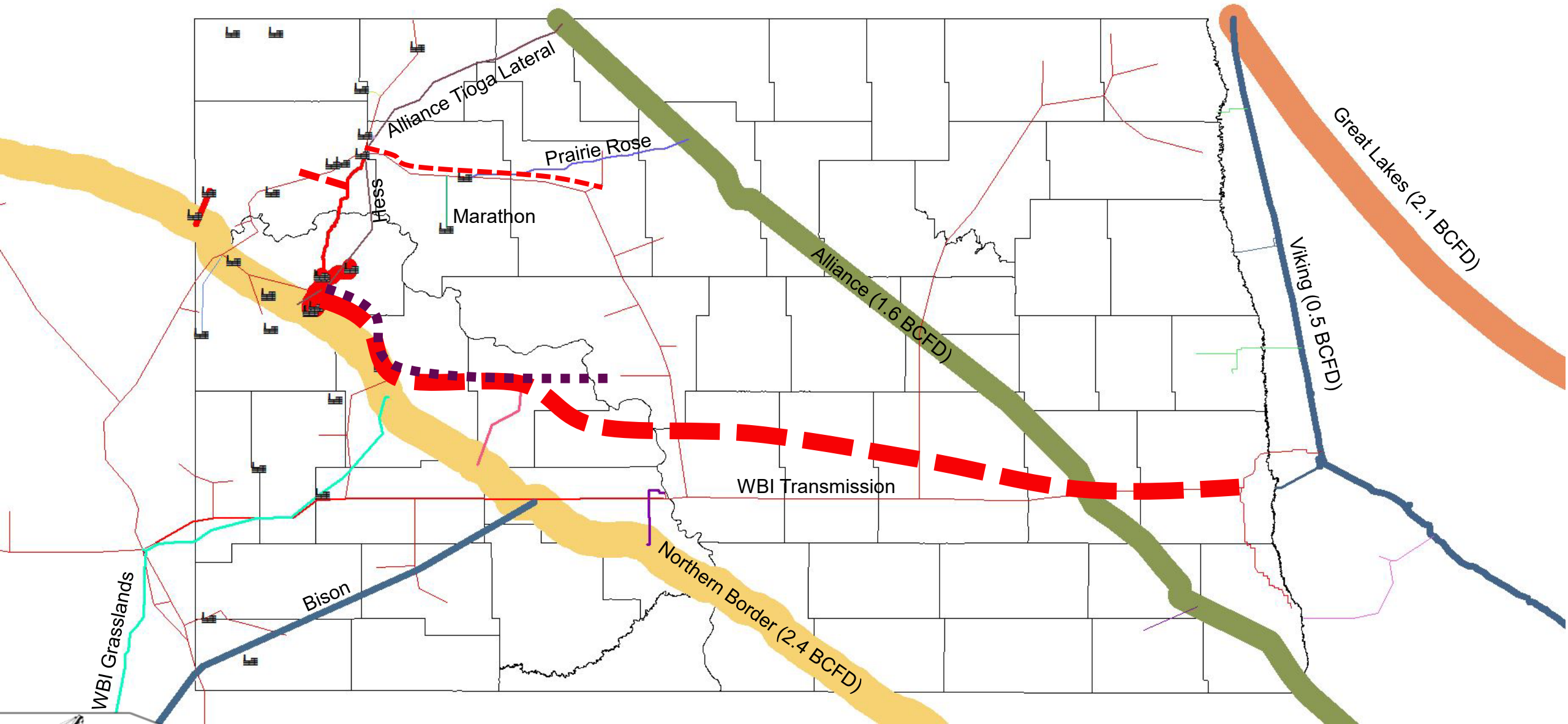
Bakken East Major Milestone Schedule



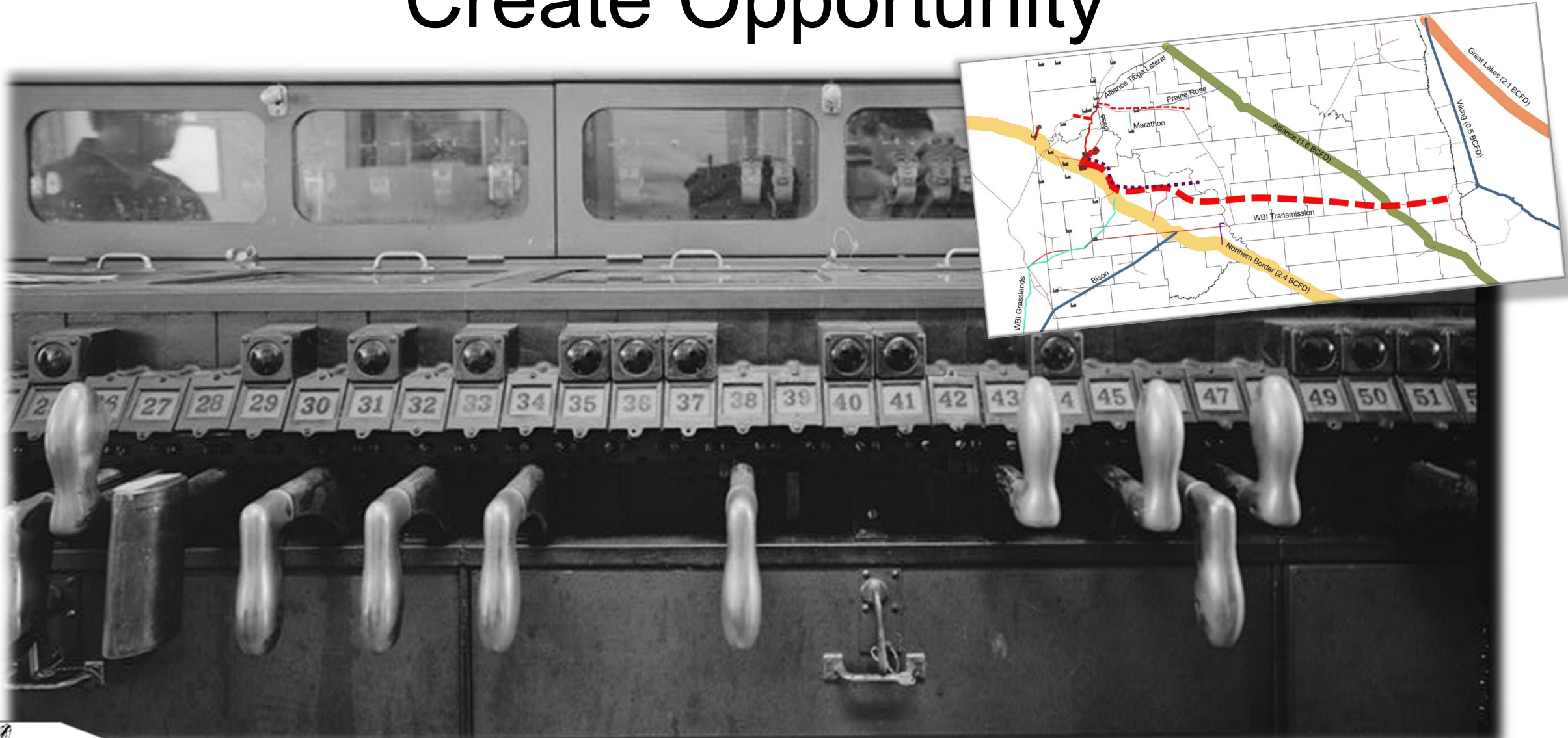
Going East: Statewide Benefits of Interconnections



Residue Gas Pipeline Capacity Visualization



Physical Infrastructure and Nimble Markets Create Opportunity



Potential Demand Growth*

Bakken East / Intensity Pipelines

- Combined demand of 1.5+ BCFD

Industrial Demand

- Proposed Cerilon gas to liquids
- Proposed Minot iron processing
- Potential fertilizer project(s)

Power Generation

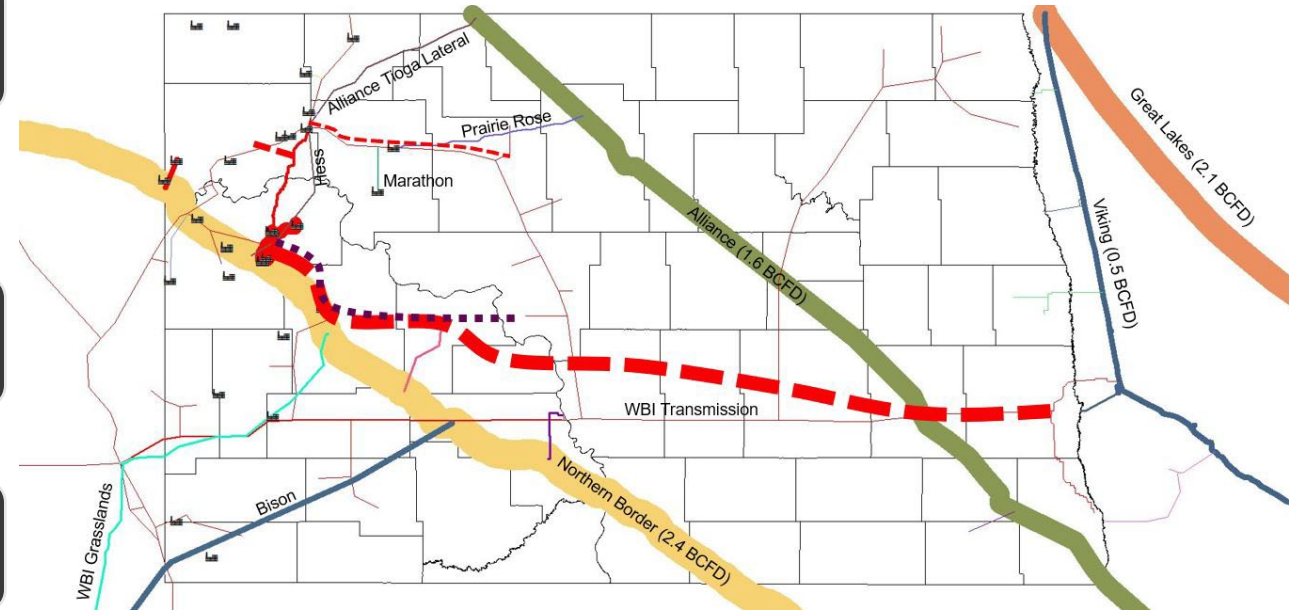
- Incremental gas fired generation for grid & data

Enhanced Oil Recovery (EOR)

- Rich gas use for EOR impacts local residue supply/demand dynamics

Residential & Commercial

- Incremental growth in residential & commercial sectors



Potential Incremental Supply Options*

Local Production Growth

- Increase of 1.2-1.5 BCFD of residue gas by mid-2030's

Canadian Supply

- Increased or expanded Port of Morgan flows
- Alliance deliveries reduced or reversed
- Continued or expanded Viking deliveries
- Other potential inbound options from existing pipelines

Rockies Supply

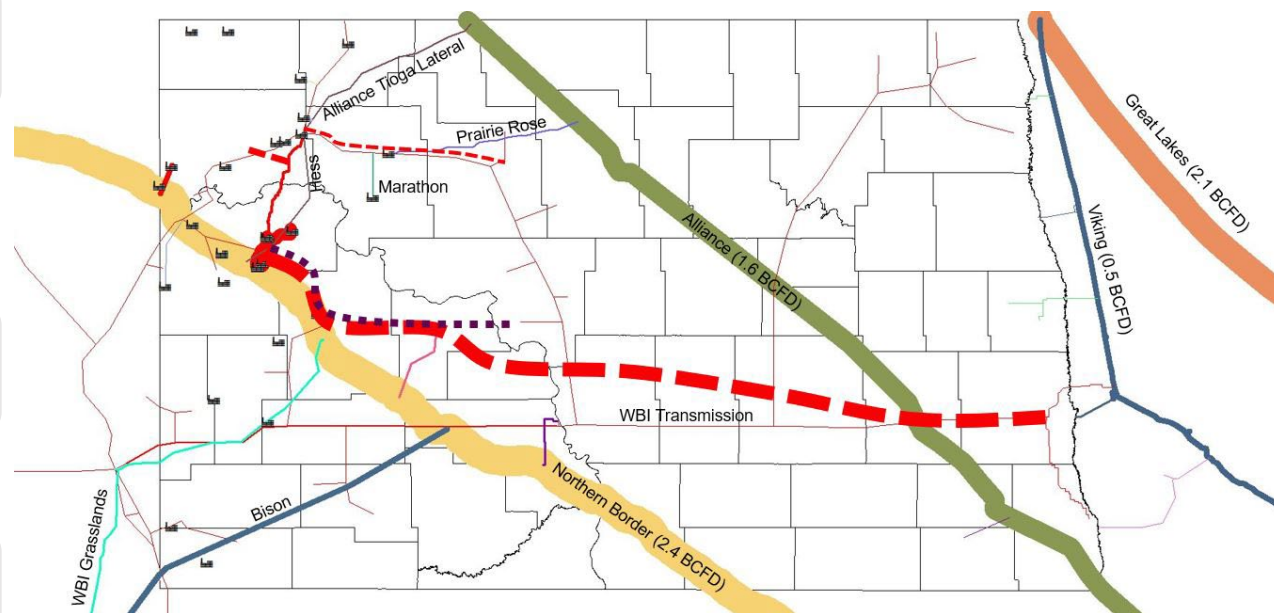
- Grasslands deliveries reduced or reversed
- Bison deliveries reduced or reversed

Midcontinent Supply

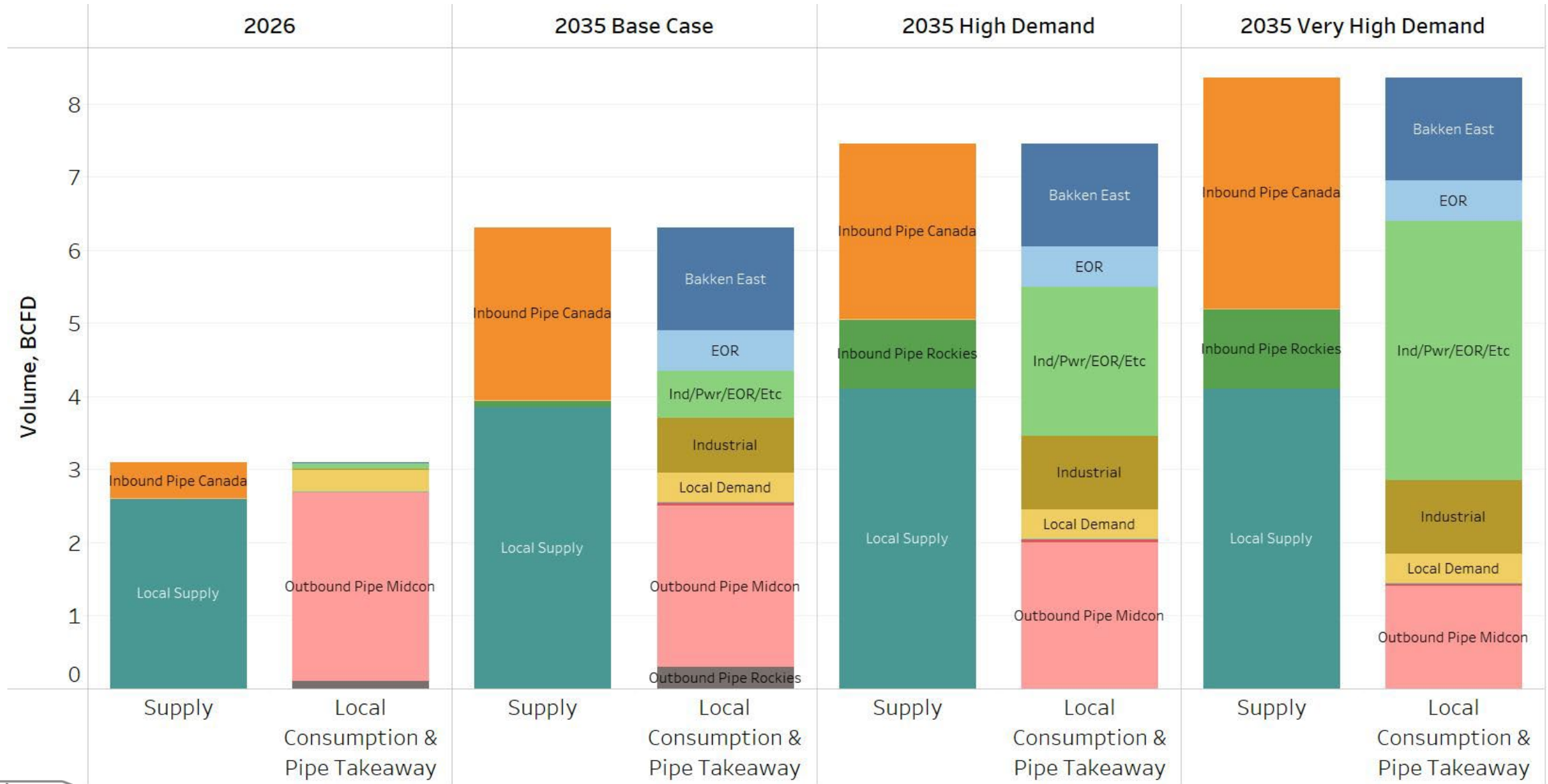
- Northern Border to Ventura reduced or reversed

Ethane Rejection

- Ethane management to support market needs



Gas Supply and Demand Modeling*



Contact Information

Justin J. Kringstad, Director
North Dakota Pipeline Authority

600 E. Boulevard Ave. Dept. 405
Bismarck, ND 58505-0840

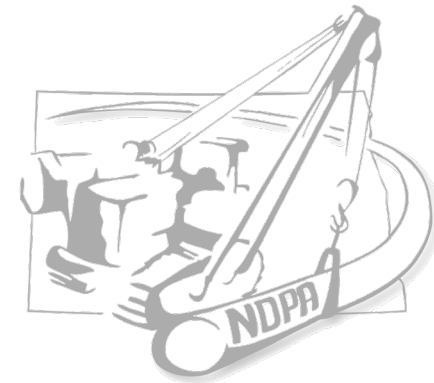
Phone: (701)220-6227
E-mail: jjkringstad@ndpipelines.com



**Know what's below.
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Website:

www.northdakotapipelines.com



Director's Update | August 25, 2026

North Dakota Oil & Gas Production & Activity Level Summary

Activity:

- ND rig count has increased to 33 rigs. This is an increase of 7 rigs from last month.
- The number of completions in May were 55, 65 in June and 75 in July. This is a leading indicator of more oil production possibly coming online.
- Continental Resources has stood up the 2 rigs. Previously, Continental dropped its rigs in early 2026.
- Last month 14 different operators ran rigs in the basin, this month that number stands at 19 different operators with rigs running.
- The number of drilling permits issued in July was 93, an increase from 85 in June.

Production:

- Oil production increased 2.45% from May to June.
- June oil production was at 1,152,796 bbls/day, gas production at 3.583 BCF/d. Oil revenue forecast is 1,150,000 bbls/day. We are above the oil forecast number in volume and pricing.
- Top oil producing counties in ND are (in order): McKenzie, Williams, Dunn, Mountrail, Divide. These counties produce 96.5% of ND oil statewide.

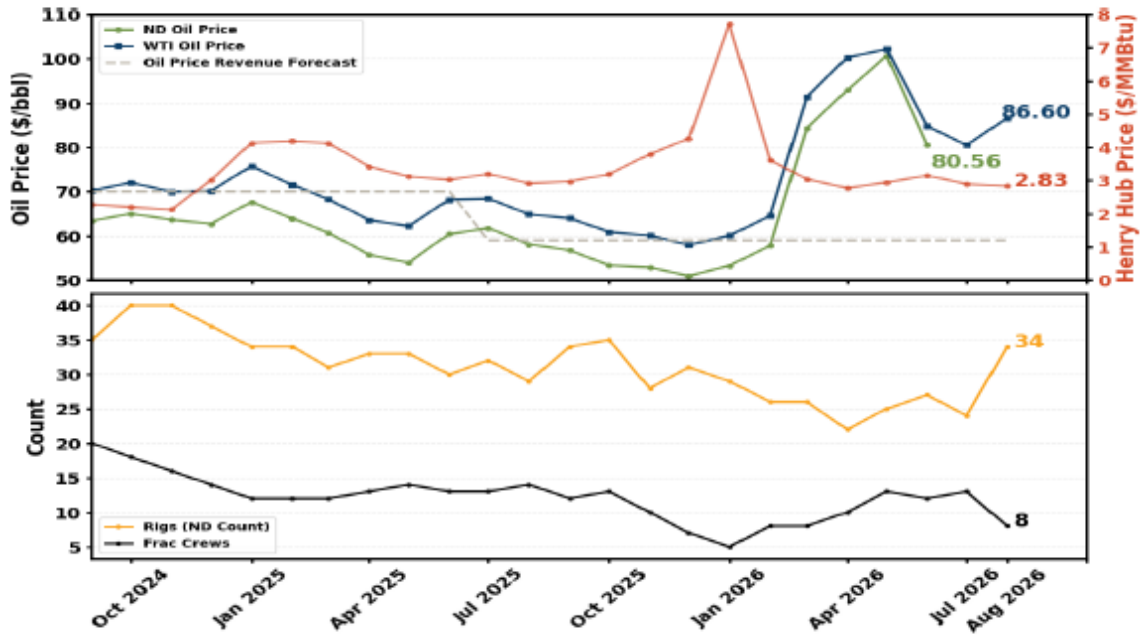
Operation Efficiencies:

- 47% of new wells are 2-mile laterals and 3-mile laterals declined to 44%, with 4-mile laterals stayed the same at 9%.
- Estimated average producing lateral length is 13,602' while just two years ago this number was 11,000'. This is an incredible 2,600' increase in lateral length. This is a real operational efficiency that yields multiple other benefits.

Revenue:

- ND Tax May oil price came in at \$80.56 (revenue forecast at \$59)

PRICING AND ACTIVITY LEVELS



RIG COUNT SUMMARY

Operator	13-Jul-26	19-Aug-26	Change
Chevron (Hess)	3	3	0
Chord Energy (Enerplus, Whiting & Oasis)	4	3	-1
Conoco (Burlington Resources)	4	3	-1
Continental Resources	1	2	+1
Devon Energy	4	4	0
Eben Operating	0	1	+1
EOG Resources	1	1	0
Firebird Services, LLC	0	1	+1
Formentera Operations	1	1	0
Hunt Oil	1	1	0
Iron Oil Operating	0	1	+1
Koda Resources Operating	1	2	+1
Murex Petroleum	0	1	+1
Petro-Hunt	1	1	0
Phoenix Operating	1	3	+2
Silver Hill Energy Operating	1	1	0
Slawson Exploration Company	1	1	0
XTO Energy	2	2	0
Zavanna Energy Operating	0	1	+1
Total	26	33	+7

Legislation

- The DMR is preparing for the 70th Legislative session. We see a need for a few minor updates consistent with industry growth and technology advancements for new and existing industries.

Geological Survey

- There is an aerial gravity survey being completed in the NE part of the state. It is ~2/3 complete and expect to have all flights and data processing completed next year. This project is in collaboration with the USGS, searching for changes in the earth's gravity & mapping basement rocks, in hopes of finding metallurgical ore.
- Fossil dig in Pembina Gorge State Park yielded a 6' fish that will be recovered next season.
- Critical minerals drilling begins another phase next month. This is the second season of the bi-ennium and the focus will be on the Rhame bed in Morton, Grant, Adams, Hettinger and Bowman counties. The NDGS expects to get ~25-30 cores.

Succession Planning

- At the end of September our Finance Manager Robyn Loumer will be retiring after 31 years with the state of North Dakota. We have hired a Finance Manager to fill that vacancy and this individual will start with the agency on September 1st.
- Backfill for Paleontology Manager is underway, as Dr. Clint Boyd was promoted to the State Geologist and leader of the NDGS

Budget

- The DMR has submitted our next bi-ennium budget per the Governor's budget outline. The next step will be to meet with OMB regarding the submitted budget.

August 11, 2026

PUBLIC FINANCE AUTHORITY ADVISORY COMMITTEE

RECOMMENDATION TO THE INDUSTRIAL COMMISSION

The Advisory Committee, at its August 11, 2026 meeting, reviewed, discussed, and recommends approval of a \$6,221,000 Clean Water State Revolving Fund Program loan to the City of Casselton.

North Dakota Public Finance Authority
Advisory Committee

Keith Lund, Chairman
Linda Svihovec
John Phillips

Memorandum

To: Public Finance Authority Advisory Committee
Miles Silbert, Public Financial Management LLC
Kylee Merkel, Bank of North Dakota

From: DeAnn Ament, Executive Director

Date: July 15, 2026

Re: City of Casselton
Clean Water State Revolving Fund

Purpose of the Project:

Replacement of the water mains, storm and sanitary sewer, and streets in downtown Casselton.

Project Cost:

CWSRF Request	\$6,221,000
DWSRF Request	1,624,000
DWR Cost Share	78,920
Local Funds	1,747,675
Project Total	\$9,671,595

Population to Benefit from the Project: 2,479

Population Served by the System: 2,479

The requested term for the Clean Water State Revolving Fund (CWSRF) loans is 30 years. The City will issue \$2,306,000 improvement bonds payable from special assessments. The improvement bonds will be a contingent general obligation of the City, backed by the statutory requirement that the City levy a general deficiency tax in the event that the revenues from the collection of special assessments are not sufficient to pay the debt service on the improvement bonds. Accordingly, the average annual payment will be approximately \$96,573.

In addition, the City of Casselton will issue \$3,915,000 revenue bonds payable with city sales tax dedicated to infrastructure. The average annual payment for the revenue bonds will be \$163,296. The debt reserve requirement will be \$177,625 and the 110% coverage requirement will be \$179,626.

City Sales Tax

The City collects 2% city sales tax dedicated for 1) infrastructure and capital improvements; 2) parks and recreation; 3) job development by business retention, expansion and recruitment; and 4) property tax relief. Currently, there are no bonds secured with the city sales tax and there are no other pledges of the 2% dedicated to infrastructure. The city sales tax will also be pledged for the repayment of the new Drinking Water State Revolving Fund (DWSRF) bond.

Excess City Sales Tax Collections:

	2025	2024	2023	2022	2021
2% City Sales Tax	\$800,626	\$837,662	\$777,123	\$626,873	\$595,608
Proforma SRF Payments	231,068	231,068	231,068	231,068	231,068
Excess Sales Tax	\$569,558	\$606,594	\$546,055	\$395,805	\$364,540

The current 2% city sales tax dedicated to infrastructure will be sufficient to meet the 110% net operating coverage requirement.

Water and Sewer Rates:

The City's water users pay a monthly base rate of \$21 which includes 2,000 gallons. Over 2,000 gallons, the usage charge is \$9/1,000 gallons. The residential sewer users pay a monthly base rate of \$18.46 per month if year's average is less than 3,600 gallons, \$27.76 per month if year's average is 3,600 – 8,000 gallons and \$35.96 per month. All users pay a monthly sewer surcharge of \$23.86.

Water and Sewer Fund Net Operating Coverage:

	2022	2023	Unaudited 2024	Unaudited 2025
Operating Revenue	\$1,238,264	\$1,252,517	\$1,278,196	\$1,284,395
Operating Expenses	886,087	887,889	705,806	723,493
Net Operating Expense	352,177	364,628	572,390	560,902
Depreciation	145,919	145,922	-	-
Adjusted Net Operating Revenue	\$498,096	\$510,550	\$572,390	\$560,902
Revenue Bond Payments	\$264,175	\$264,500	\$259,700	\$264,900
Net Operating Coverage	189%	193%	220%	212%

Outstanding Indebtedness December 31, 2025:

	Original Amount	Outstanding Amount
Improvement Bonds ¹	\$17,354,898	\$12,060,390
Revenue Bonds ¹	4,147,610	2,125,000
Total	\$21,502,508	\$14,185,390

¹ All payments have been made as agreed. The City has two CWSRF and one DWSRF loans with outstanding balances of \$2,515,000.

The average annual payment of all outstanding debt including this request and the Clean Water State Revolving Fund request is \$1,822,240 which is \$735 per resident.

Population and Employment

The City of Casselton is located in Cass County on Interstate 94. Based on the 2020 census, the total population is 2,479; this is an increase of 150 from the 2010 census. The largest employers in the City are Central Cass School employs 150, ND Soybean Processors (agriculture) employs 80, and Tharaldson Ethanol (manufacturer) has approximately 73 employees.

Casselton K-12 School Enrollment:

<i>Projected</i>				
2022-2023	2023-2024	2024-2025	2025-2026	2026-2027
1,000	1,003	998	1,017	1,020

The City's 2025 taxable valuation was \$16,928,244. This is an increase of \$5,797,286 from the 2021 taxable valuation.

Property Tax Levies and Collections as of 4/30/2026:

Levy Year	Dollar Amount of Levy	Amount Collected to Date of Application	Percentage Collected
2025	\$1,200,211	\$1,071,234	89%
2024	\$1,652,101	\$1,493,452	90%
2023	\$1,530,073	\$1,454,361	95%

Special Assessments Certified for Collection as of 4/30/2026:

Year	Dollar Amount	Amount Collected to Date of Application	Percentage Collected
2025	\$1,221,192	\$973,929	80%
2024	\$1,256,420	\$1,242,828	99%
2023	\$812,842	\$812,842	100%

City of Casselton Mill Levy History:

Year	City	School	Park District	State and County	Other	Total for Each Year
2025	90.80	111.93	19.80	47.73	12.15	282.41
2024	104.66	113.63	21.33	46.00	12.96	298.58
2023	96.69	115.43	20.75	46.00	12.96	291.83
2022	94.79	121.31	21.81	48.00	8.04	293.95
2021	98.34	120.63	21.87	48.75	8.04	297.63



Memorandum

TO: DeAnn Ament, Executive Director
North Dakota Public Finance Authority

FROM: PFM Financial Advisors LLC

DATE: August 12, 2026

RE: Marketplace Analysis - Clean Water State Revolving Fund Program
City of Casselton

The City of Casselton ("City") has presented a request to the Authority and the North Dakota Department of Environmental Quality ("Department") for a \$3,915,000 revenue loan and \$2,306,000 special assessment loan under the Clean Water State Revolving Fund Program ("CWSRF Program"). The CWSRF Program is used to make subsidized interest rate loans to political subdivisions for the purpose of constructing various wastewater treatment projects and landfill projects as approved by the Department in accordance with federal and state regulations and an updated Intended Use Plan prepared by the Department.

The City intends to use the proceeds for the replacement of water mains, storm, sanitary sewer and streets in downtown Casselton.

The municipal securities to be acquired by the Authority for the \$3,915,000 loan will be revenue bonds payable with city sales tax dedicated to the infrastructure. The proposed term of the loan is 30 years with a subsidized interest rate of 1.50%. The City's average annual payment under the proposed loan will be approximately \$163,296, indicating a 110% net revenue coverage requirement of approximately \$179,626. The City will be required to deposit \$177,625 into a reserve fund with payments of \$35,525 per year for the first five years of the loan. The city sales tax dedicated to infrastructure has excess of approximately \$364,540, \$395,805, \$546,055, \$606,594 and \$569,558 for 2021-2025, respectively. The current 2% city sales tax dedicated to infrastructure will be sufficient to meet the 110% net operating coverage requirement.

The municipal securities to be acquired by the Authority for the \$2,306,000 loan will be improvement bonds of the City payable from special assessments levied against the benefited property. The proposed term of the loan is 30 years with a subsidized interest rate of 1.50%. The City's average annual payment under the proposed loan will be approximately \$96,573. The improvement bonds will be a contingent general obligation of the City, which will be required by law to levy a general deficiency tax if the revenues collected from the levy of special assessments are insufficient to make the debt service payments.

As of December 31, 2025, the City has \$12,060,390 of Improvement Bonds and \$2,125,000 of Revenue Bonds outstanding. The City currently has two CWSRF and one DWSRF loan outstanding with a combined total balance of \$2,515,000. The City is current in its payments for its outstanding Authority loans.

Funding for the construction of the City's projects has been included in a list of approved projects as prepared and updated by the Department. As an authorized participant in the CWSRF Program, the City will benefit substantially from the subsidized fixed rate loans made under the Program. Consequently, no other financing mechanism can provide a greater cost advantage than that offered by the CWSRF Program.

Memorandum

To: Industrial Commission

From: Kylee Merkel, Business Banker
Bank of North Dakota

Date: July 20, 2026

RE: City of Casselton
Clean Water State Revolving Fund Program

ND Public Finance Authority has delivered to BND their memo which recommends approval of a \$6,221,000 loan to the City of Casselton under the Clean Water State Revolving Fund (CWSRF). The entire cost of the project is \$9,671,595, with Drinking Water State Revolving Fund (DWSRF) providing a \$1,624,000 loan, Department of Water Resources providing a \$78,920 state cost-share grant and the City using \$1,747,675 of local funds on hand.

The project will replace water mains, storm and sanitary sewer and streets in downtown Casselton. The requested loan term is 30 years. The City will issue a \$3,915,000 revenue bond payable with a city sales tax collections and a \$2,306,000 improvement bond payable with special assessment collections. The annual payment will average \$163,296 for the revenue bond and \$96,573 for the improvement bond.

Sales Tax Collections:

The City collects 2% city sales tax dedicated to infrastructure and capital improvements, parks and recreation, job development by business retention, expansion and recruitment, and property tax relief. Currently there is no debt secured by sales tax collections. The city sales tax will also be pledged for repayment of the DWSRF loan. The city sales tax collections will be sufficient to service the proposed CWSRF and DWSRF debt service.

	2021	2022	2023	2024	2025
2% Sales Tax Collections	\$ 595,608	\$ 626,873	\$ 777,123	\$ 837,662	\$ 800,626
SRF Debt Requirements	\$ 231,068	\$ 231,068	\$ 231,068	\$ 231,068	\$ 231,068
Excess Sales Tax	\$ 364,540	\$ 395,805	\$ 546,055	\$ 606,594	\$ 569,558

Water & Sewer Fund:

The City sewer connections pay a monthly base rate based on previous year's average usage: \$18.46 for usage up to 3,600 gallons, \$27.76 for usage ranging from 3,600 to 8,000 gallons, and \$35.96 for usage over 8,000 gallons. In addition, all users pay a monthly sewer surcharge of \$23.86. The City water connections pay a monthly base rate of \$21.00, which includes 2,000 gallons. Usage for 2,000 to 8,000 gallons is an additional \$9.00 per 1,000 gallons and \$11.00 per 1,000 gallons over 8,000 gallons.

Water and Sewer Fund	2021	2022	2023
Operating Revenue	1,253,692	1,238,264	1,252,517
Operating Expenses	-811,253	-886,087	-887,889
Net Operating Revenue	442,440	352,177	364,628
Plus: Depreciation	145,919	145,919	145,922
Adjusted Net Operating Income	588,359	498,096	510,550
Current Debt Service	288,669	264,175	264,500
Debt Service Coverage	204%	189%	193%

Outstanding Debt (as of December 31, 2025):

	<u>Original Amount</u>	<u>Current Balance</u>
Improvement Bonds	17,354,898	12,060,390
Revenue Bonds	4,147,610	2,125,000
	21,502,508	14,185,390

Average annual debt service requirements are estimated at \$1,822,240, which is an average of \$735.07 per resident.

Historical census populations for the City of Casselton were 2,479 in 2020, 2,329 in 2010 and 1,885 in 2000. The largest employers in the City are Central Cass Public Schools, ND Soybean Processors and Tharaldson Ethanol.

Based upon the PFA recommendation and the benefits obtained with this project, BND concurs with their evaluation and support of the request.

Kylee Merkel

Kylee Merkel
Business Banker



moore
engineering, inc.

August 11, 2026

PUBLIC FINANCE AUTHORITY ADVISORY COMMITTEE

RECOMMENDATION TO THE INDUSTRIAL COMMISSION

The Advisory Committee, at its August 11, 2026 meeting, reviewed, discussed, and recommends approval of a \$2,100,000 increase to a previously approved \$2,000,000 (total \$4,100,000) Clean Water State Revolving Fund Program loan to the City of Fessenden.

North Dakota Public Finance Authority
Advisory Committee

Keith Lund, Chairman
Linda Svihovec
John Phillips

Memorandum

To: Public Finance Authority Advisory Committee
 Miles Silbert, Public Financial Management LLC
 Kylee Merkel, Bank of North Dakota

From: DeAnn Ament, Executive Director

Date: August 10, 2026

Re: City of Fessenden
 Clean Water State Revolving Fund

Purpose of the Project:

Reconstruct the lagoons within the existing footprint bringing them up to current design standards.

Project Cost:

CWSRF Request	\$2,100,000
CWSRF Original Request	2,000,000
State Wastewater Grant HB 1577	1,900,000
Project Total	\$6,000,000

Population to Benefit from the Project: 462

Population Served by the System: 462

The requested term for the Clean Water State Revolving Fund (CWSRF) loans is 30 years. The City of Fessenden will issue revenue bonds payable with water and sewer revenues and city sales tax. The average annual payment for the revenue bond will be \$168,855. The debt reserve requirement will be \$180,250 and the 110% coverage requirement will be \$185,741.

Water and Sewer Rates:

The City has 230 residential and 55 commercial sewer users. Effective May 2025, the City increased the monthly base rate from \$15 to \$40. The City's water users' monthly base rate is \$31. The water volume rate increased from \$8 to \$11.75/1,000 gallons. The infrastructure fee increased from \$5 to \$10 per month. These increases are expected to generate an additional revenue of \$191,550.

Water and Sewer Fund Net Operating Coverage:

			Unaudited	Unaudited
	2022	2023	2024	2025
Interest Revenue	\$397	\$555	\$157	\$131
Operating Revenue	341,816	355,180	354,334	441,990
Operating Expenses	461,090	422,888	353,775	288,607
Net Operating Expense	(118,876)	(67,153)	716	153,514
Depreciation	150,756	150,756	-	-
Adjusted Net Operating Revenue	\$31,880	\$83,603	\$716	\$153,514
Revenue Bond Payments	\$45,621	\$42,300	\$39,789	\$39,789
Net Operating Coverage	70%	198%	2%	386%
Proforma Rate Increase Revenue	\$191,550	\$191,550	\$191,550	\$95,775
Proforma City Sales Tax Transfer	30,000	30,000	30,000	30,000
Proforma CWSRF Payment	\$168,855	\$168,855	\$168,855	\$168,855
Proforma Net Operating Coverage	118%	145%	107%	134%

City Sales Tax

The City collects 2% city sales tax dedicated to general infrastructure improvements. Previously, there were no bonds secured with the city sales tax and no other pledges of the 2% dedicated to infrastructure. The City plans to transfer \$30,000 of City Sales Tax to the water, sewer, and garbage fund.

City Sales Tax Collections:

	2025	2024	2023	2022	2021
2% City Sales Tax	\$131,108	\$115,021	\$100,426	\$101,869	\$99,164

With the projected rate increases and annual sales tax transfer, the net operating revenues should be sufficient to meet the 110% net operating coverage.

Outstanding Indebtedness June 30, 2026:

	Original Amount	Outstanding Amount
Improvement Bonds	\$2,618,434	\$2,036,522
Revenue Bonds ¹	3,037,555	2,068,327
Total	\$5,655,989	\$4,104,849

¹ All payments have been made as agreed. The City has this original CWSRF and one Drinking Water State Revolving Fund (DWSRF) loan with total outstanding balances of \$2,068,327.

The average annual payment of all outstanding debt including this request is \$350,337 which is \$758 per resident.

Population and Employment

The City of Fessenden is located in Wells County. Based on the 2020 census, the total population is 462; this is a decrease of 17 from the 2010 census. The largest employers in the City are Fessenden-Bowdon School District employs 39, Cenex (convenience store) with 26 employees and CenDak (agriculture) has 18 employees.

Fessenden K-12 School Enrollment:

<i>Projected</i>				
2022-2023	2023-2024	2024-2025	2025-2026	2026-2027
170	163	180	180	180

The City's 2025 taxable valuation was \$1,373,784. This is an increase of \$191,937 from the 2021 taxable valuation.

Property Tax Levies and Collections as of 8/7/2026:

Levy Year	Dollar Amount of Levy	Amount Collected to Date of Application	Percentage Collected
2025	\$154,466	\$150,115	97%
2024	\$149,775	\$144,413	96%
2023	\$144,158	\$139,857	97%

Special Assessments Certified for Collection as of 8/7/2026:

Year	Dollar Amount	Amount Collected to Date of Application	Percentage Collected
2025	\$130,042	\$123,914	95%
2024	\$130,781	\$130,511	100%
2023	\$131,188	\$140,195	107%

City of Fessenden Mill Levy History:

Year	City	School	Park District	State and County	Other	Total for Each Year
2025	118.62	84.97	42.29	93.19	10.82	349.89
2024	116.27	83.88	42.34	92.43	10.71	345.63
2023	116.46	79.71	42.51	80.86	10.87	330.41
2022	100.14	79.22	42.58	81.31	9.17	312.42
2021	102.38	78.57	42.99	80.25	9.23	313.42



Memorandum

TO: DeAnn Ament, Executive Director
North Dakota Public Finance Authority

FROM: PFM Financial Advisors LLC

DATE: August 12, 2026

RE: Marketplace Analysis - Clean Water State Revolving Fund Program
City of Fessenden

The City of Fessenden (“City”) has presented a request to the Authority and the North Dakota Department of Environmental Quality (“Department”) for a \$2,100,000 increase to a previously approved \$2,000,000 for a total of \$4,100,000 under the Clean Water State Revolving Fund Program (“CWSRF Program”). The CWSRF Program is used to make subsidized interest rate loans to political subdivisions for the purpose of constructing various wastewater treatment projects and landfill projects as approved by the Department in accordance with federal and state regulations and an updated Intended Use Plan prepared by the Department.

The City intends to use the proceeds to reconstruct the lagoons within the existing footprint and bring them up to current design standards.

The municipal securities to be acquired by the Authority will be revenue bonds of the City payable from water and sewer revenues and city sales tax. The proposed term of the loan is 30 years with a subsidized interest rate of 1.50%. The City’s average annual payment under the proposed loan will be approximately \$168,855, indicating a 110% net revenue coverage requirement of approximately \$185,741. The City will be required to deposit \$180,250 into a reserve fund with payments of \$36,050 per year for the first five years of the loan. In May 2025, the City increased the monthly sewer base rate from \$15 to \$40, the water volume rate from \$8 to \$11.75/1,000 gallons, and the monthly infrastructure fee from \$5 to \$10, which will generate approximately \$191,550 of additional annual revenue. The proforma net operating coverage of the water and sewer fund was 1.18x, 1.45x, 1.07x, and 1.34 for 2021-2025, respectively. In addition, the City collects a 2% city sales tax dedicated to general infrastructure improvements which is currently not pledged to any other debt. The City plans to transfer \$30,000 of city sales tax to the water and sewer fund annually. The rate increases and annual city sales tax transfer will provide sufficient net revenues to meet the 110% net operating coverage requirement.

As of June 30, 2026, the City has \$2,036,522 of Improvement Bonds and \$2,068,327 of Revenue Bonds outstanding. The City currently has one CWSRF and one DWSRF loan outstanding with a combined total balance of \$2,068,327. The City is current in its payments for its outstanding Authority loans.

Funding for the construction of the City's projects has been included in a list of approved projects as prepared and updated by the Department. As an authorized participant in the CWSRF Program, the City will benefit substantially from the subsidized fixed rate loans made under the Program. Consequently, no other financing mechanism can provide a greater cost advantage than that offered by the CWSRF Program.

Memorandum

To: Industrial Commission

From: Kylee Merkel, Business Banker
Bank of North Dakota

Date: August 10, 2026

RE: City of Fessenden
Clean Water State Revolving Fund Program

ND Public Finance Authority has delivered to BND their memo which recommends approval of a \$2,100,000 increase to an existing loan (from \$2,000,000 to \$4,100,000) to the City of Fessenden under the Clean Water State Revolving Fund (CWSRF). The entire cost of the project is \$6,000,000, with the City receiving a \$1,900,000 State Wastewater Grant from HB 1577.

The project will reconstruct the lagoons and bring them up to current design standards. The requested loan term is 30 years. The City will issue a revenue bond payable with utility fund revenues and city sales tax. The annual payment will average \$168,855.

Debt Service Coverage:

Utility Fund	2021	2022	2023	Projected
Operating Revenue	326,332	341,816	355,180	355,180
Projected Rate Increase				191,550
Interest Revenue	496	397	555	555
Operating Expenses	-418,856	-461,090	-422,888	-422,888
Net Operating Revenue	-92,029	-118,876	-67,153	124,397
Plus: City Sales Tax Transfer In	0	0	0	30,000
Plus: Depreciation	150,756	150,756	150,756	150,756
Adjusted Net Operating Income	58,727	31,880	83,603	305,153
Current Debt Service	48,642	45,621	42,300	42,300
Proposed Debt Service				168,855
Total Debt Service				211,155
Debt Service Coverage	121%	70%	198%	145%

The City currently serves 285 sanitary sewer connections. The City increased utility fees in May 2025. All users pay a monthly sewer base rate of \$40.00 (a \$25 increase), a monthly water base rate of \$31.00, a lagoon maintenance fee of \$10.00 (a \$5 increase), and a volume charge of \$11.75 per 1,000 gallons (a \$3.75 increase). These increases will generate an estimated \$191,550 of increased utility fund revenues. In addition, the City will transfer \$30,000 of City Sales Tax to the utility fund each year. The existing revenues, combined with the rate increases and sales tax transfer, will generate sufficient net operating revenues to service both the new and existing debt.

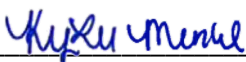
Outstanding Debt (as of June 30, 2026):

	Original Amount	Current Balance
Water Revenue Bonds	3,037,555	2,068,327
Water/Sewer Improvement Bonds	2,618,434	2,036,522
	5,655,989	4,104,849

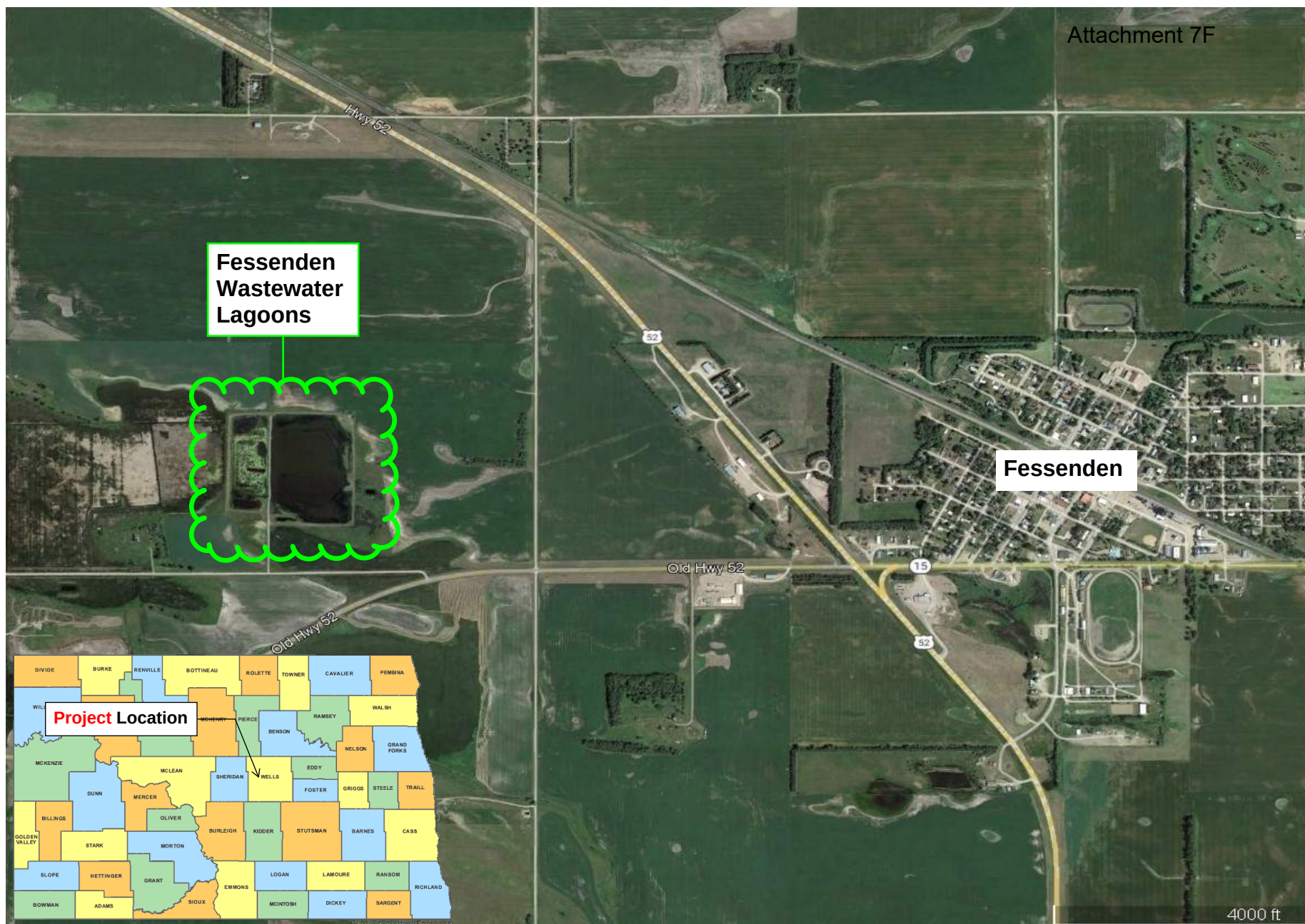
Average annual debt service requirements are estimated at \$350,337, which is an average of \$758.31 per resident.

Historical census populations for the City of Fessenden were 462 in 2020, 477 in 2010 and 616 in 2000. The largest employers in the City are Fessenden Bowden School, Cenex and Cen Dak.

Based upon the PFA recommendation and the benefits obtained with this project, BND concurs with their evaluation and support of the request.



Kylee Merkel
Business Banker



August 11, 2026

PUBLIC FINANCE AUTHORITY ADVISORY COMMITTEE

RECOMMENDATION TO THE INDUSTRIAL COMMISSION

The Advisory Committee, at its August 11, 2026 meeting, reviewed, discussed, and recommends approval of a \$2,042,000 Drinking Water State Revolving Fund Program loan to the City of Grand Forks.

North Dakota Public Finance Authority
Advisory Committee

Keith Lund, Chairman
Linda Svihovec
John Phillips

Memorandum

To: Public Finance Authority Advisory Committee
 Miles Silbert, Public Financial Management LLC
 Kylee Merkel, Bank of North Dakota

From: DeAnn Ament, Executive Director

Date: July 17, 2026

Re: City of Grand Forks
 Drinking Water State Revolving Fund

Purpose of the Project:

Phase III expansion of the City watermain which will provide potable water service to the commercial and residential users in the recently annexed land north of Grand Forks.

Project Cost:

DWSRF Request	\$2,042,000
Total Project Cost	\$2,042,000

Population to Benefit from the Project: 40

Population Served by the System: 59,166

The requested term for the Drinking Water State Revolving Fund (DWSRF) loan is 30 years. Accordingly, the average annual payment on the loan will be approximately \$85,483. The City will issue improvement bonds payable with special assessments. The improvement bonds will be a contingent general obligation of the City, backed by the statutory requirement that the City levy a general deficiency tax in the event that the revenues from the collection of special assessments are not sufficient to pay the debt service on the improvement bonds.

Water Rates:

The City monthly water base charge for the 14,265 residential users is \$9.92 and the flow fee is \$5.12/1,000 gallon. The 1,867 commercial users pay a monthly base charge of \$17.57 and a flow fee of \$4.99/1,000 gallons.

Water Fund Net Operating Coverage:

Unaudited

	2022	2023	2024	2025
Interest Revenue	\$ 69,846	\$ 587,637	\$ 771,050	\$ 148,513
Operating Revenue	12,915,729	13,684,826	14,250,144	15,037,785
Operating Expenses	11,356,989	11,694,756	12,598,807	13,828,806
Net Operating Revenue	1,628,586	2,577,707	2,422,387	1,357,492
Infrastructure Sales Tax Transfer	2,138,360	2,030,000	2,854,599	2,932,764
Noncash: Pension Adjustment	193,078	-	-	-
Adjusted Net Operating Revenue	\$3,960,024	\$4,607,707	\$5,276,986	\$4,290,256
Revenue Bond Payments	\$3,277,856	\$3,091,806	\$3,228,637	\$3,108,409
Net Operating Coverage	121%	149%	163%	138%

Outstanding Indebtedness December 31, 2025:

	Original Amount	Outstanding Amount
General Obligation Bonds	\$ 2,735,000	\$ 235,000
Improvement Bonds ¹	190,397,989	137,670,605
Water/Sewer Revenue Bonds¹	220,560,641	155,069,825
Sales Tax Revenue Bonds	140,585,000	32,215,000
Total	\$ 554,278,630	\$325,190,430

¹ All payments have been made as agreed. The City has eight CWSRF and four DWSRF loans with outstanding balances of \$151,462,102. In April 2026, an additional CWSRF of \$4,235,000 and a DWSRF \$4,543,000 loan were approved but had not closed.

The average annual payment of all outstanding debt including this request is \$25,236,816 which is \$427 per resident.

Population and Employment

The City of Grand Forks is located in Grand Forks County 82 miles north of Fargo on Interstate 29. Based on the 2020 census, the total population is 59,166; this is an increase of 6,328 from the 2010 census. The largest employers in the City are University of North Dakota which has 5,562 employees, Altru Health Services with 3,400 employees, and Grand Forks Air Force Base employs 2,897. A potato processing plant had their ground breaking on July 8, 2026 in the City and is anticipated to open in 2028.

Grand Forks K-12 School Enrollment:

<i>Projected</i>				
2022-2023	2023-2024	2024-2025	2025-2026	2026-2027
7,407	7,440	7,428	7,679	7,679

The City's 2025 taxable valuation was \$296,649,483. This is an increase of \$56,890,788 over the 2021 taxable valuation.

Property Tax Levies and Collections as of 6/30/2026:

Levy Year	Dollar Amount of Levy	Amount Collected to Date of Application	Percentage Collected
2025	\$23,679,732	\$21,550,853	91%
2024	\$25,167,836	\$23,883,993	95%
2023	\$25,843,457	\$24,658,716	95%

Special Assessments Certified for Collection as of 6/30/2026:

Year	Dollar Amount	Amount Collected to Date of Application	Percentage Collected
2025	\$10,826,309	\$10,085,883	93%
2024	\$10,161,885	\$9,729,770	96%
2023	\$9,286,257	\$9,231,557	99%

City of Bottineau Mill Levy History:

Year	City	School	Park District	State and County	Total for Each Year
2025	91.94	129.78	36.27	85.12	343.11
2024	92.25	130.50	36.79	87.00	346.54
2023	96.37	131.69	37.31	87.16	352.53
2022	96.84	110.79	37.80	82.63	328.06
2021	97.02	111.00	37.88	79.29	325.19



Memorandum

TO: DeAnn Ament, Executive Director
North Dakota Public Finance Authority

FROM: PFM Financial Advisors LLC

DATE: August 12, 2026

RE: Marketplace Analysis - Drinking Water State Revolving Fund Program
City of Grand Forks

The City of Grand Forks (the “City”) has presented a request to the Authority and the North Dakota Department of Environmental Quality (“Department”) for a \$2,042,000 loan under the Drinking Water State Revolving Fund Program (“DWSRF Program”). The DWSRF Program is used to make subsidized interest rate loans to political subdivisions for the purpose of constructing various water treatment, distribution and storage facilities as approved by the Department in accordance with federal and state regulations and an updated Intended Use Plan prepared by the Department.

The City intends to use the proceeds for expansion of the watermain to provide potable water service to the commercial and residential users in the recently annexed land north of Grand Forks.

The municipal securities to be acquired by the Authority will be improvement bonds of the City payable from special assessments levied against the benefited property. The proposed term of the loan is 30 years with a subsidized interest rate of 1.50%. The City's average annual payment under the proposed loan will be approximately \$85,483. The improvement bonds will be a contingent general obligation of the City, which will be required by law to levy a general deficiency tax if the revenues collected from the levy of special assessments are insufficient to make the debt service payments.

As of December 31, 2025, the City has \$235,000 of General Obligation Bonds, \$137,670,605 of Improvement Bonds, \$155,069,825 of Water/Sewer Revenue Bonds, and \$32,215,000 of Sales Tax Revenue Bonds outstanding. The City currently has eight CWSRF and four DWSRF loans with outstanding balances of \$151,462,102. The City is current in its payments for its outstanding Authority loans.

Funding the construction of the City's improvements has been included in a list of approved uses as prepared and updated by the Department. As an authorized participant in the DWSRF Program, the City will benefit substantially from the subsidized fixed rate loans made under the Program. Consequently, no other financing mechanism can provide a greater cost advantage than that offered by the DWSRF Program.

Memorandum

To: Industrial Commission

From: Kylee Merkel, Business Banker
Bank of North Dakota

Date: July 20, 2026

RE: City of Grand Forks
Drinking Water State Revolving Fund Program

ND Public Finance Authority has delivered to BND their memo which recommends approval of a \$2,042,000 loan to the City of Grand Forks under the Drinking Water State Revolving Fund (DWSRF). The entire cost of the project is \$2,042,000, with DWSRF financing the full cost of the project. The project will complete Phase 3 of watermain extensions to service a recently annexed section of land north of the City.

The City will issue improvement bonds payable with special assessment collections. The annual payment will average \$85,483. The requested loan term is 30 years.

Water Fund:

Water Fund	2022	2023	2024
Operating Revenue	12,915,729	13,684,826	14,250,144
Interest Revenue	69,846	587,637	771,050
Operating Expenses	-11,356,989	-11,694,756	-12,598,807
Net Operating Revenue	1,628,586	2,577,707	2,422,387
Infrastructure Sales Tax Transfer	2,138,360	2,030,000	2,854,599
Plus: Pension Adjustment	193,078	0	0
Adjusted Net Operating Income	3,960,024	4,607,707	5,276,986
Current Debt Service	3,277,856	3,091,806	3,228,637
Debt Service Coverage	121%	149%	163%

The City currently serves 14,265 residential connections which pay a monthly base rate of \$9.92 and a usage charge of \$5.12 per 1,000 gallons. The City currently serves 1,867 commercial connections which pay a monthly base rate of \$17.57 and a usage charge of \$4.99 per 1,000 gallons.

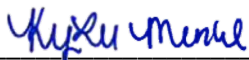
Outstanding Debt (as of December 31, 2025):

	<u>Original Amount</u>	<u>Current Balance</u>
General Obligation Bonds	2,735,000	235,000
Special Assessment Bonds	190,397,989	137,670,605
Sales Tax Revenue Bonds	140,585,000	32,215,000
Water & Sewer Revenue Bonds	220,560,641	155,069,825
	554,278,630	325,190,430

Average annual debt service requirements are estimated at \$25,236,816, which is an average of \$426.54 per resident.

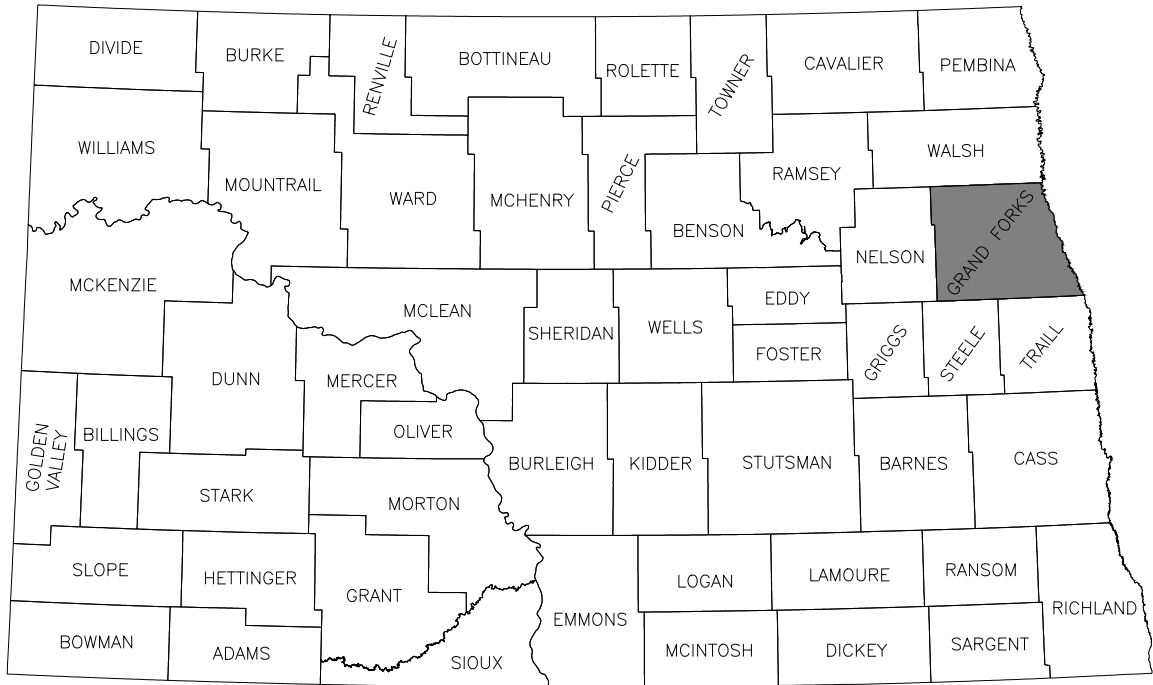
The system currently serves 58,882 people. Historical census populations for the City of Grand Forks were 59,166 in 2020, 52,838 in 2010 and 49,321 in 2000. The largest employers in the City are University of North Dakota, Altru Health System and Grand Forks Air Force Base.

Based upon the PFA recommendation and the benefits obtained with this project, BND concurs with their evaluation and support of the request.



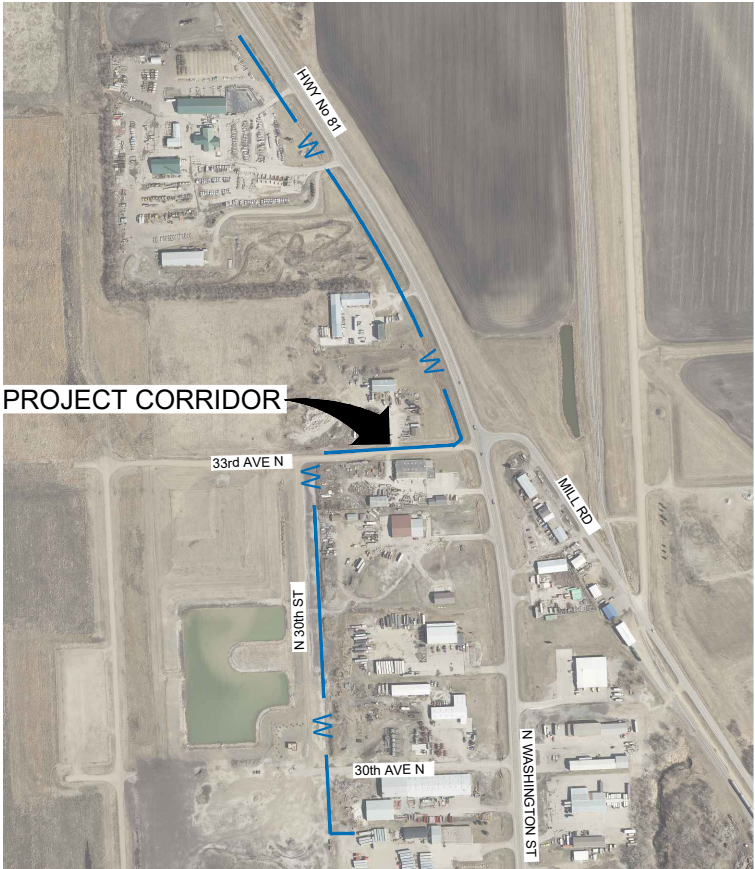
Kylee Merkel
Business Banker

File: W:\Grand Forks\00105-2022-022\CAD Drawings\General\Plan Sheets\Front_Sheet.dwg



STATE OF NORTH DAKOTA

1 PROJECT LOCATION MAP
C002 GRAND FORKS COUNTY



2 PROJECT VICINITY MAP
C002 GRAND FORKS COUNTY



3 PROJECT AERIAL MAP
C002 GRAND FORKS COUNTY



STATUS: **FOR CONSTRUCTION**

ANNEXATION WATERMAIN EXPANSION PHASE 3

Advanced Engineering and Environmental Services, LLC www.ae2s.com

SHEET TITLE:

LOCATION MAP

CLIENT:

CITY OF GRAND FORKS
GRAND FORKS, ND

PREPARED BY: MRK

CHECKED BY: WJM

APPROVED BY: WJM

PROJECT NO: 00105-2022-022

DATE: MARCH 2026

ALT. PROJECT NO: GF CITY 8576

SHEET DESIGNATOR:

GEN

SHEET NO:

C002

Plotted By: Mike Kocort Date: Wednesday, March 25, 2026

Memorandum

To: Industrial Commission: Governor Kelly Armstrong, Attorney General Drew H. Wrigley, Agriculture Commissioner Doug Goehring

From: DeAnn Ament, Executive Director

Date: August 11, 2026

Re: City of Bowman, Drinking Water State Revolving Fund
City of Casselton, Drinking Water State Revolving Fund
City of Stanley, Drinking Water State Revolving Fund
City of Stanley, Clean Water State Revolving Fund

Under current policy, the Public Finance Authority can make loans under the State Revolving Fund Program in an amount not to exceed \$2,000,000 and under the Capital Financing Program in an amount not to exceed \$500,000 without seeking the final approval of the Industrial Commission. Within this policy, once the loan has been approved, the Public Finance Authority is required to provide the details of the loan to the Industrial Commission. Accordingly, the Public Finance Authority and its Advisory Committee used this policy to approve the following loans.

The committee reviewed the City of Bowman's Drinking Water State Revolving Fund (DWSRF) application for a \$1,193,000 loan towards a \$2,981,600 project. Department of Water Resource's Cost Share awarded \$1,788,600. The project will replace two existing tanks with a new 600,000-gallon water storage reservoir. The requested term for the loan is 20 years. The City will issue revenue bonds payable with water user fees.

The committee reviewed the City of Casselton's DWSRF application for a \$1,624,000 loan towards a \$9,671,595 project. The Clean Water State Revolving Fund (CWSRF) will provide a \$6,221,000 loan, Department of Water Resource's Cost Share awarded \$78,920 and local funds of \$1,747,675 will complete the funding. The project will replace water mains, storm, and sanitary sewer mains that have reached the end of their useful life which will reduce operation and maintenance costs and improve system reliability. The requested term for the loan is 30 years. The City will issue revenue bonds payable with city sales tax.

The committee reviewed the City of Stanley's application for a \$300,000 DWSRF loan and a \$350,000 CWSRF loan towards a \$2,399,807 project. Local funds will complete the funding with \$1,749,807. The project includes phase 3 of the street reconstruction, watermain and sanitary sewer main service replacements. The requested loan term is 30

years. The City will issue improvement bonds payable from special assessments. The improvement bonds will be a contingent general obligation of the City, backed by the statutory requirement that the City levy a general deficiency tax in the event that the revenues from the collection of special assessments are not sufficient to pay the debt service on the improvement bonds.

The Public Finance Authority's Advisory Committee approved these loans at their August 11, 2026, meeting.

Memorandum

To: Public Finance Authority Advisory Committee
Miles Silbert, Public Financial Management LLC
Kylee Merkel, Bank of North Dakota

From: DeAnn Ament, Executive Director

Date: August 5, 2026

Re: City of Bowman
Drinking Water State Revolving Fund

Purpose of the Project:

Replace two existing tanks with a new 600,000-gallon water storage reservoir.

Project Cost:

DWSRF Request	\$1,193,000
DWR Cost Share	1,788,600
Project Total	\$2,981,600

Population to Benefit from the Project: 1,416

Population Served by the System: 1,416

The requested term for the Drinking Water State Revolving Fund (DWSRF) loans is 20 years. The City will issue revenue bonds payable with water revenues. The average annual payment for the revenue bonds will be \$69,290. The 110% coverage requirement will be \$76,219 and the required debt service reserve will be \$74,095.

Water Rates:

The City has 717 residential and 127 commercial water users that pay a monthly rate of \$9/1,000 gallons.

Water Fund Net Operating Coverage:

	Unaudited		
	2023	2024	2025
Operating Revenue	\$399,949	\$472,775	\$442,381
Operating Expenses	345,773	363,816	332,703
Net Operating Income	\$54,176	\$108,959	\$109,677
Depreciation	7,734	9,651	-
Adjusted Net Operating Revenue	\$61,910	\$118,610	\$109,677
Proforma DWSRF Payment	\$69,290	\$69,290	\$69,290
Proforma Net Operating Coverage	89%	171%	158%

The existing revenues will generate sufficient net operating revenue to meet the required net operating coverage requirement.

Outstanding Indebtedness June 30, 2026:

	Original Amount	Outstanding Amount
Revenue Bonds ¹	\$3,967,000	\$29,449
Total	\$3,967,000	\$29,449

¹ All payments have been made as agreed. The City has one Clean Water State Revolving Fund (CWSRF) loan with an outstanding balance of \$29,449.

The average annual payment of all outstanding debt including this request is \$111,078 which is \$76 per resident.

Population and Employment

The City of Bowman is located in Bowman County 74 miles southwest of Dickinson. Based on the 2020 census, the total population is 1,470; this is a decrease of 180 from the 2010 census. The largest employers in the City are Southwest Healthcare employs 131, Bowman County School employs 100, and Bowman County has approximately 45 employees.

Bowman K-12 School Enrollment:

				<i>Projected</i>
2022-2023	2023-2024	2024-2025	2025-2026	2026-2027
521	498	510	508	508

The City's 2025 taxable valuation was \$5,747,310. This is an increase of \$589,174 from the 2021 taxable valuation.

Property Tax Levies and Collections as of 8/5/2026:

Levy Year	Dollar Amount of Levy	Amount Collected to Date of Application	Percentage Collected
2025	\$562,609	\$537,743	96%
2024	\$515,724	\$510,827	99%
2023	\$480,009	\$479,007	100%

Special Assessments Certified for Collection as of 8/5/2026:

Year	Dollar Amount	Amount Collected to Date of Application	Percentage Collected
2025	-	-	-
2024	-	-	-
2023	\$1,476	\$1,476	100%

City of Bowman Mill Levy History:

Year	City	School	Park District	State and County	Total for Each Year
2025	100.84	99.87	37.70	61.22	299.63
2024	98.76	93.31	36.64	58.61	273.04
2023	93.82	89.82	33.88	55.52	273.04
2022	90.90	89.65	35.41	53.81	269.77
2021	87.94	86.78	35.25	52.43	262.40



Memorandum

TO: DeAnn Ament, Executive Director
North Dakota Public Finance Authority

FROM: PFM Financial Advisors LLC

DATE: August 12, 2026

RE: Marketplace Analysis - Drinking Water State Revolving Fund Program
City of Bowman

The City of Bowman (the “City”) has presented a request to the Authority and the North Dakota Department of Environmental Quality (“Department”) for a \$1,193,000 loan under the Drinking Water State Revolving Fund Program (“DWSRF Program”). The DWSRF Program is used to make subsidized interest rate loans to political subdivisions for the purpose of constructing various water treatment, distribution and storage facilities as approved by the Department in accordance with federal and state regulations and an updated Intended Use Plan prepared by the Department.

The City intends to use the proceeds to replace two existing tanks with a new 600,000-gallon water storage reservoir.

The municipal securities to be acquired by the Authority will be revenue bonds of the City payable from water revenues. The proposed term of the loan is 20 years with a subsidized interest rate of 1.50%. The City’s average annual payment under the proposed loan will be approximately \$69,290 indicating a 110% net revenue coverage requirement of approximately \$76,219. The City will be required to deposit \$74,095 into a reserve fund with payments of \$14,819 per year for the first five years of the loan. The City's water fund adjusted proforma net operating coverage was approximately 0.89x, 1.71x, and 1.58x for 2023-2025, respectively. The current water revenues will be sufficient to meet the 110% net operating coverage requirement.

As of June 30, 2026, the City has \$29,449 of Revenue Bonds outstanding. The City currently has one CWSRF loan with an outstanding balance of \$29,449. The City is current in its payments for its outstanding Authority loans.

Funding the construction of the City’s improvements has been included in a list of approved uses as prepared and updated by the Department. As an authorized participant in the DWSRF Program, the City will benefit substantially from the subsidized fixed rate loans made under the Program. Consequently, no other financing mechanism can provide a greater cost advantage than that offered by the DWSRF Program.

Memorandum

To: Industrial Commission

From: Kylee Merkel, Business Banker
Bank of North Dakota

Date: August 6, 2026

RE: City of Bowman
Drinking Water State Revolving Fund Program

ND Public Finance Authority has delivered to BND their memo which recommends approval of a \$1,193,000 loan to the City of Bowman under the Drinking Water State Revolving Fund (DWSRF). The entire cost of the project is \$2,981,600, with Department of Water Resources providing a \$1,788,600 state cost-share grant.

The project will replace two existing water storage tanks with a new water storage reservoir. The City will issue revenue bonds payable with water user fees. The requested loan term is 20 years. The annual payment will average \$69,290.

Debt Service Coverage:

Water Fund	2022	2023	2024	Projected
Operating Revenue	403,529	399,949	472,775	472,775
Operating Expenses	-405,093	-345,773	-363,816	-363,816
Net Operating Revenue	-1,564	54,176	108,959	108,959
Add: Depreciation	8,355	7,734	9,651	9,651
Adjusted Net Operating Income	6,791	61,910	118,610	118,610
Proposed Debt Service				69,290
Debt Service Coverage				171%

The City currently serves 717 residential connections and 127 commercial connections. All connections pay a volume charge of \$9.00 per 1,000 gallons of usage. The existing revenues will generate sufficient coverage to service the proposed debt service requirements.

Debt Outstanding (as of June 30, 2026):

	Original Amount	Current Balance
Sewer Revenue Bonds	3,967,000	29,449
	3,967,000	29,449

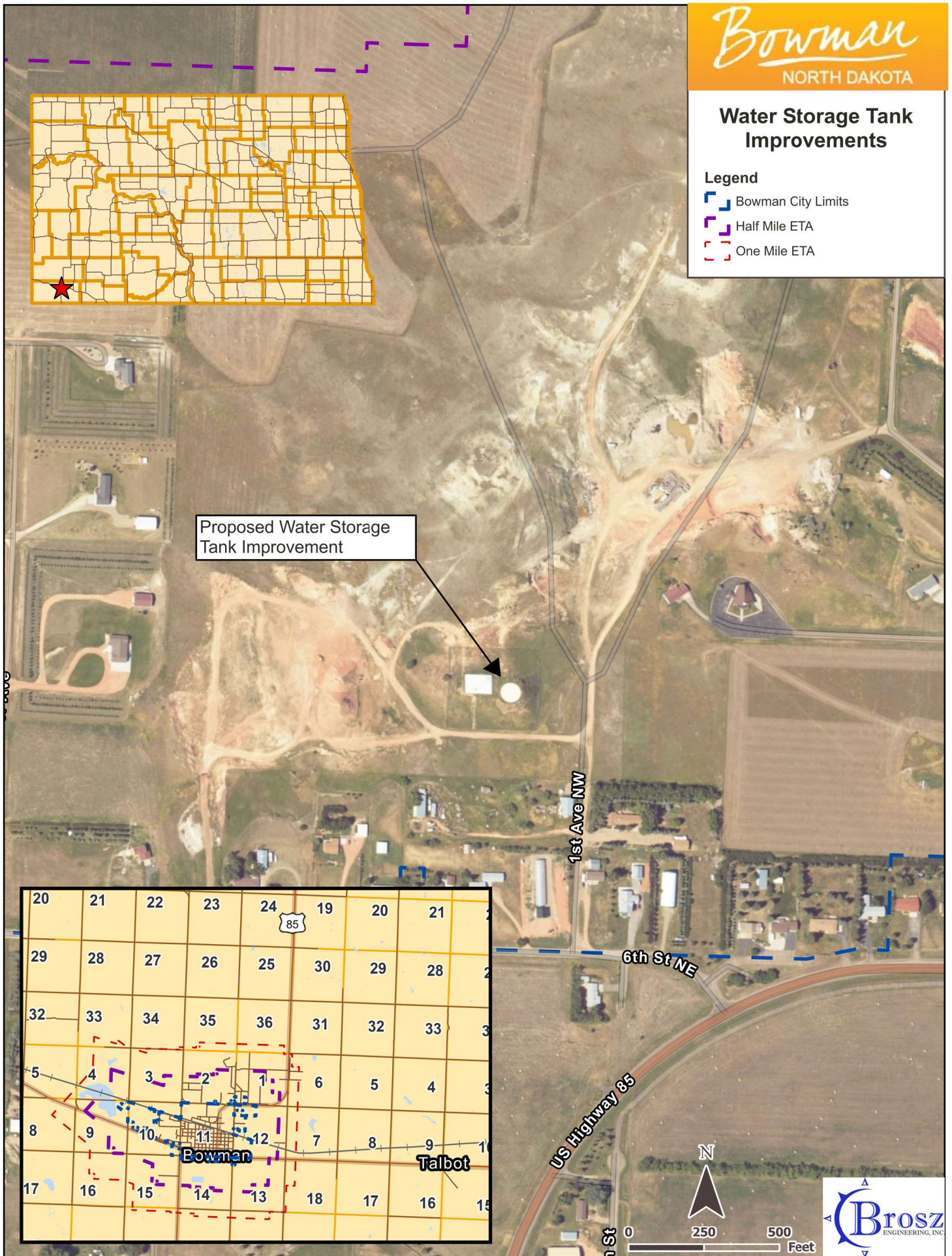
Annual debt service requirements are estimated at \$111,078, which is an average of \$75.56 per resident.

Historical census populations for the City of Bowman were 1,470 in 2020, 1,650 in 2010 and 1,600 in 2000. The largest employers in the City are Southwest Healthcare, Bowman County School and Bowman County Courthouse.

Based upon the PFA recommendation and the benefits obtained with this project, BND concurs with their evaluation and support of the request.



Kylee Merkel
Business Banker



Memorandum

To: Public Finance Authority Advisory Committee
Miles Silbert, Public Financial Management LLC
Kylee Merkel, Bank of North Dakota

From: DeAnn Ament, Executive Director

Date: July 15, 2026

Re: City of Casselton
Drinking Water State Revolving Fund

Purpose of the Project:

Replacement of the water mains, storm and sanitary sewer, and streets in downtown Casselton.

Project Cost:

DWSRF Request	\$1,624,000
CWSRF Request	6,221,000
DWR Cost Share	78,920
Local Funds	1,747,675
Project Total	\$9,671,595

Population to Benefit from the Project: 2,479

Population Served by the System: 2,479

The requested term for the Drinking Water State Revolving Fund (DWSRF) loans is 30 years. The City of Casselton will issue \$1,624,000 revenue bonds payable with city sales tax dedicated to infrastructure. The average annual payment for the revenue bonds will be \$67,772. The debt reserve requirement will be \$81,200 and the 110% coverage requirement will be \$74,549.

City Sales Tax

The City collects 2% city sales tax dedicated for 1) infrastructure and capital improvements; 2) parks and recreation; 3) job development by business retention, expansion and recruitment; and 4) property tax relief. Currently, there are no bonds secured with the city sales tax and there are no other pledges of the 2% dedicated to infrastructure. The city sales tax will also be pledged for the repayment of the new Clean Water State Revolving Fund (CWSRF) bond.

Excess City Sales Tax Collections:

	2025	2024	2023	2022	2021
2% City Sales Tax	\$800,626	\$837,662	\$777,123	\$626,873	\$595,608
Proforma SRF Payments	231,068	231,068	231,068	231,068	231,068
Excess Sales Tax	\$569,558	\$606,594	\$546,055	\$395,805	\$364,540

The current 2% city sales tax dedicated to infrastructure will be sufficient to meet the 110% net operating coverage requirement.

Water and Sewer Rates:

The City's water users pay a monthly base rate of \$21 which includes 2,000 gallons. Over 2,000 gallons, the usage charge is \$9/1,000 gallons. The residential sewer users pay a monthly base rate of \$18.46 per month if year's average is less than 3,600 gallons, \$27.76 per month if year's average is 3,600 – 8,000 gallons and \$35.96 per month. All users pay a monthly sewer surcharge of \$23.86.

Water and Sewer Fund Net Operating Coverage:

	2022	2023	Unaudited 2024	Unaudited 2025
Operating Revenue	\$1,238,264	\$1,252,517	\$1,278,196	\$1,284,395
Operating Expenses	886,087	887,889	705,806	723,493
Net Operating Expense	352,177	364,628	572,390	560,902
Depreciation	145,919	145,922	-	-
Adjusted Net Operating Revenue	\$498,096	\$510,550	\$572,390	\$560,902
Revenue Bond Payments	\$264,175	\$264,500	\$259,700	\$264,900
Net Operating Coverage	189%	193%	220%	212%

Outstanding Indebtedness December 31, 2025:

	Original Amount	Outstanding Amount
Improvement Bonds ¹	\$17,354,898	\$12,060,390
Revenue Bonds ¹	4,147,610	2,125,000
Total	\$21,502,508	\$14,185,390

¹ All payments have been made as agreed. The City has two CWSRF and one DWSRF loans with outstanding balances of \$2,515,000.

The average annual payment of all outstanding debt including this request and the Clean Water State Revolving Fund request is \$1,822,240 which is \$735 per resident.

Population and Employment

The City of Casselton is located in Cass County on Interstate 94. Based on the 2020 census, the total population is 2,479; this is an increase of 150 from the 2010 census. The largest employers in the City are Central Cass School employs 150, ND Soybean Processors (agriculture) employs 80, and Tharaldson Ethanol (manufacturer) has approximately 73 employees.

Casselton K-12 School Enrollment:

<i>Projected</i>				
2022-2023	2023-2024	2024-2025	2025-2026	2026-2027
1,000	1,003	998	1,017	1,020

The City's 2025 taxable valuation was \$16,928,244. This is an increase of \$5,797,286 from the 2021 taxable valuation.

Property Tax Levies and Collections as of 4/30/2026:

Levy Year	Dollar Amount of Levy	Amount Collected to Date of Application	Percentage Collected
2025	\$1,200,211	\$1,071,234	89%
2024	\$1,652,101	\$1,493,452	90%
2023	\$1,530,073	\$1,454,361	95%

Special Assessments Certified for Collection as of 4/30/2026:

Year	Dollar Amount	Amount Collected to Date of Application	Percentage Collected
2025	\$1,221,192	\$973,929	80%
2024	\$1,256,420	\$1,242,828	99%
2023	\$812,842	\$812,842	100%

City of Casselton Mill Levy History:

Year	City	School	Park District	State and County	Other	Total for Each Year
2025	90.80	111.93	19.80	47.73	12.15	282.41
2024	104.66	113.63	21.33	46.00	12.96	298.58
2023	96.69	115.43	20.75	46.00	12.96	291.83
2022	94.79	121.31	21.81	48.00	8.04	293.95
2021	98.34	120.63	21.87	48.75	8.04	297.63



Memorandum

TO: DeAnn Ament, Executive Director
North Dakota Public Finance Authority

FROM: PFM Financial Advisors LLC

DATE: August 12, 2026

RE: Marketplace Analysis - Drinking Water State Revolving Fund Program
City of Casselton

The City of Casselton (the “City”) has presented a request to the Authority and the North Dakota Department of Environmental Quality (“Department”) for a \$1,624,000 loan under the Drinking Water State Revolving Fund Program (“DWSRF Program”). The DWSRF Program is used to make subsidized interest rate loans to political subdivisions for the purpose of constructing various water treatment, distribution and storage facilities as approved by the Department in accordance with federal and state regulations and an updated Intended Use Plan prepared by the Department.

The City intends to use the proceeds for the replacement of water mains, storm and sanitary sewer, and streets in downtown Casselton.

The municipal securities to be acquired by the Authority will be revenue bonds of the City payable from city sales tax dedicated to infrastructure. The proposed term of the loan is 30 years with a subsidized interest rate of 1.50%. The City's average annual payment under the proposed loan will be approximately \$67,772, indicating a 110% net revenue coverage requirement of approximately \$74,549. The City will be required to deposit \$81,200 into a reserve fund with payments of \$16,240 for the first five years of the loan. The city sales tax dedicated to infrastructure has excess of approximately \$364,540, \$395,805, \$546,055, \$606,594 and \$569,558 for 2021-2025, respectively. The current 2% city sales tax dedicated to infrastructure will be sufficient to meet the 110% net operating coverage requirement.

As of December 31, 2025, the City has \$12,060,390 of Improvement Bonds and \$2,125,000 of Revenue Bonds outstanding. The City currently has two CWSRF and one DWSRF loans outstanding with a combined total balance of \$2,515,000. The City is current in its payments for its outstanding Authority loans.

Funding the construction of the City's improvements has been included in a list of approved uses as prepared and updated by the Department. As an authorized participant in the DWSRF Program, the City will benefit substantially from the subsidized fixed rate loans made under the Program. Consequently, no other financing mechanism can provide a greater cost advantage than that offered by the DWSRF Program.

Memorandum

To: Industrial Commission

From: Kylee Merkel, Business Banker
Bank of North Dakota

Date: July 20, 2026

RE: City of Casselton
Drinking Water State Revolving Fund Program

ND Public Finance Authority has delivered to BND their memo which recommends approval of a \$1,624,000 loan to the City of Casselton under the Drinking Water State Revolving Fund (DWSRF). The entire cost of the project is \$9,671,595, with Clean Water State Revolving Fund (CWSRF) providing a \$6,221,000 loan, Department of Water Resources providing a \$78,920 state cost-share grant and the City using \$1,747,675 of local funds on hand.

The project will replace water mains, storm and sanitary sewer and streets in downtown Casselton. The requested loan term is 30 years. The City will issue a revenue bond payable with a city sales tax collections. The annual payment will average \$67,772.

Sales Tax Collections:

The City collects 2% city sales tax dedicated to infrastructure and capital improvements, parks and recreation, job development by business retention, expansion and recruitment, and property tax relief. Currently there is no debt secured by sales tax collections. The city sales tax will also be pledged for repayment of \$3,915,000 of the CWSRF loan. The city sales tax collections will be sufficient to service the proposed DWSRF and CWSRF debt service.

	2021	2022	2023	2024	2025
2% Sales Tax Collections	\$ 595,608	\$ 626,873	\$ 777,123	\$ 837,662	\$ 800,626
SRF Debt Requirements	\$ 231,068	\$ 231,068	\$ 231,068	\$ 231,068	\$ 231,068
Excess Sales Tax	\$ 364,540	\$ 395,805	\$ 546,055	\$ 606,594	\$ 569,558

Water & Sewer Fund:

The City water connections pay a monthly base rate of \$21.00, which includes 2,000 gallons. Usage for 2,000 to 8,000 gallons is an additional \$9.00 per 1,000 gallons and \$11.00 per 1,000 gallons over 8,000 gallons. The City sewer connections pay a monthly base rate based on previous year's average usage: \$18.46 for usage up to 3,600 gallons, \$27.76 for usage ranging from 3,600 to 8,000 gallons, and \$35.96 for usage over 8,000 gallons. In addition, all users pay a monthly sewer surcharge of \$23.86.

Water and Sewer Fund	2021	2022	2023
Operating Revenue	1,253,692	1,238,264	1,252,517
Operating Expenses	-811,253	-886,087	-887,889
Net Operating Revenue	442,440	352,177	364,628
Plus: Depreciation	145,919	145,919	145,922
Adjusted Net Operating Income	588,359	498,096	510,550
Current Debt Service	288,669	264,175	264,500
Debt Service Coverage	204%	189%	193%

Outstanding Debt (as of December 31, 2025):

	Original Amount	Current Balance
Improvement Bonds	17,354,898	12,060,390
Revenue Bonds	4,147,610	2,125,000
	21,502,508	14,185,390

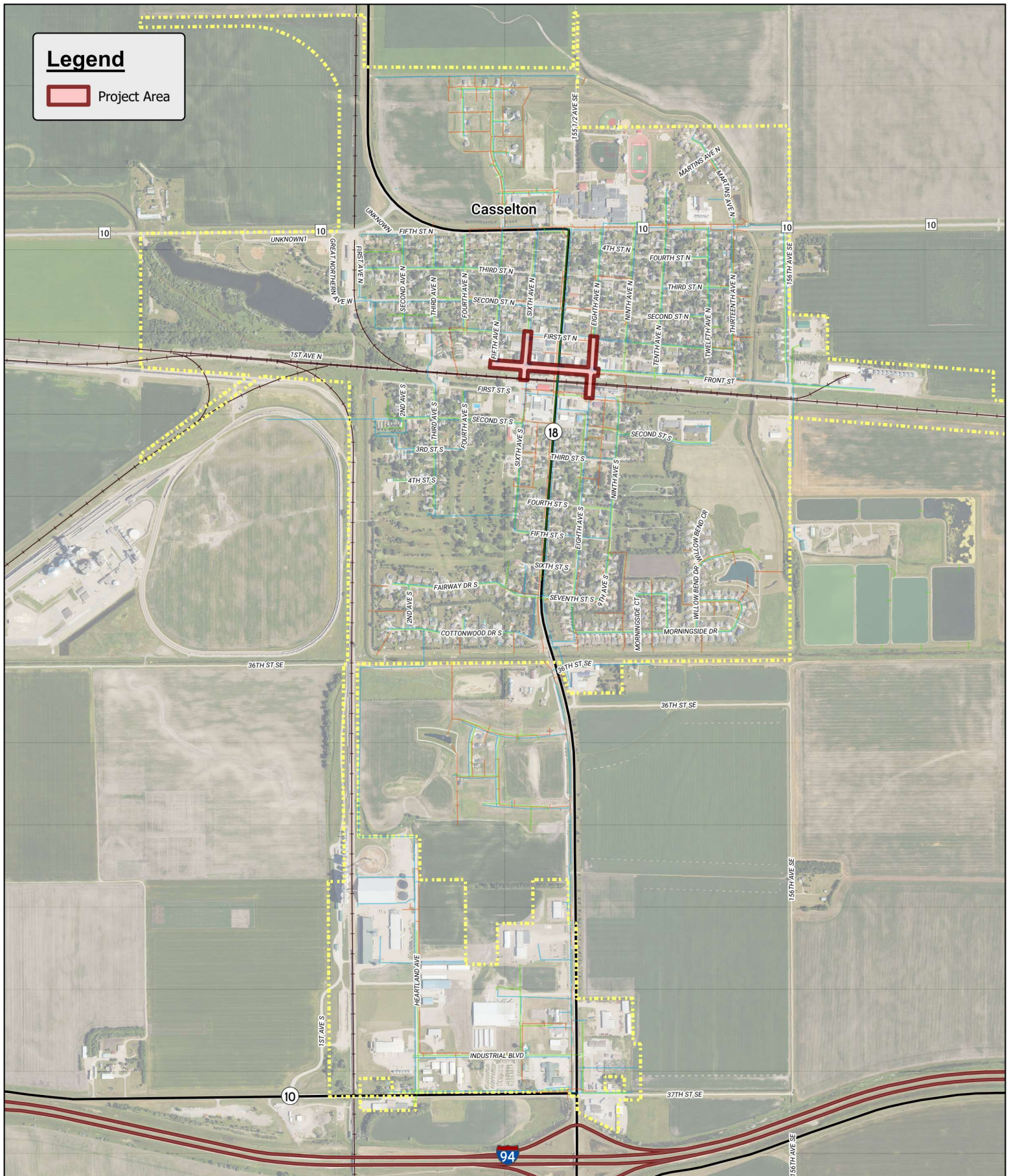
Average annual debt service requirements are estimated at \$1,822,240, which is an average of \$735.07 per resident.

Historical census populations for the City of Casselton were 2,479 in 2020, 2,329 in 2010 and 1,885 in 2000. The largest employers in the City are Central Cass Public Schools, ND Soybean Processors and Tharaldson Ethanol.

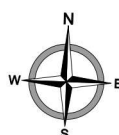
Based upon the PFA recommendation and the benefits obtained with this project, BND concurs with their evaluation and support of the request.

Kylee Merkel

Kylee Merkel
Business Banker



WATER SYSTEM IMPROVEMENTS 2025 CASSELTON, NORTH DAKOTA



Created By: KMV Date Created: 01/06/2025 Date Saved: 02/09/26 Date Exported: 02/09/26
Exported By: tanner.schmidt Parcel Date: State Parcels N/A Aerial Image: NAIP Elevation Data: N/A
Horizontal Datum: NAD 1983 StatePlane North Dakota North FIPS 3301 Feet Vertical Datum: NAVD1988
T:\Projects\23000\23053\10 ArcPro\23053 DWR Exhibit\23053 DWR Exhibit.aprx

Memorandum

To: Public Finance Authority Advisory Committee

From: DeAnn Ament, Executive Director

Date: August 4, 2026

Re: City of Stanley
Drinking Water State Revolving Fund

Purpose of the Project:

Phase 3 of the street reconstruction, watermain and sanitary sewer main service replacements.

Project Cost:

DWSRF Request	\$300,000
CWSRF Request	350,000
Local Funds	1,749,807
Project Total	\$2,399,807

Population to Benefit from the Project: 2,321

Population Served by the System: 2,321

The requested term for the Drinking Water State Revolving Fund (DWSRF) loans is 30 years. Accordingly, the average annual payment will be approximately \$12,542. The City will issue improvement bonds payable from special assessments. The improvement bonds will be a contingent general obligation of the City, backed by the statutory requirement that the City levy a general deficiency tax in the event that the revenues from the collection of special assessments are not sufficient to pay the debt service on the improvement bonds.

Water Rates:

The City's water users pay a monthly base rate of \$18.50 for residential, \$21.25 for commercial, and \$47.50 for high-volume commercial connections with an annual water usage over 100,000 gallons. The usage charge is \$8/1,000 gallons with a minimum charge of 1,000 gallons within the city limits and \$11/1,000 gallons with a minimum charge of 1,000 gallons for connections outside the city limits.

Water Fund Net Operating Coverage:

	2023	2024	2025
Interest Revenue	\$5,067	\$19,918	\$19,383
Operating Revenue	943,350	1,422,296	1,436,338
Operating Expenses	924,498	1,060,748	1,021,531
Net Operating Income	23,919	381,466	434,190
Depreciation	77,100	84,960	84,960
Capital Improvements Expensed	-	123,763	-
Well Water and WAWSA Net Revenue¹	-	(445,313)	(505,327)
Adjusted Net Operating Revenue	\$101,019	\$144,875	\$13,823
Revenue Bond Payments	\$57,248	\$63,499	\$45,353 ²
Net Operating Coverage	176%	228%	30%

¹ Well water and WAWSA net revenue have not been pledged and should have been excluded from the audited information for 2024 and 2025. They will not be included in future water fund net operating revenue.

² The only water revenue bonds will be paid in full on September 1, 2026.

Outstanding Indebtedness June 30, 2026:

	Original Amount	Outstanding Amount
Improvement Bonds ³	\$5,300,299	\$2,167,467
Revenue Bonds ³	1,662,901	17,000
Total	\$6,963,200	\$2,184,467

³ All payments have been made as agreed. The City has four DWSRF and four Clean Water State Revolving Fund (CWSRF) loans with outstanding balances of \$1,234,467.

The average annual payment of all outstanding debt including this request and the CWSRF request is \$303,630 which is \$131 per resident.

Population and Employment

The City of Stanley is located in Mountrail County, 55 miles west of Minot on US Highway 2. Based on the 2020 census, the total population is 2,321; this is an increase of 863 from the 2010 census. The largest employers in the City are Mountrail County Medical Center employs 151, Stanley Public School employs 137, and Mountrail County has approximately 133 employees.

Stanley K-12 School Enrollment:

<i>Projected</i>				
2022-2023	2023-2024	2024-2025	2025-2026	2026-2027
743	753	767	776	790

The City's 2025 taxable valuation was \$14,544,073. This is a decrease of \$771,225 from the 2021 taxable valuation.

Property Tax Levies and Collections as of 6/30/2026:

Levy Year	Dollar Amount of Levy	Amount Collected to Date of Application	Percentage Collected
2025	\$738,683	\$680,987	92%
2024	\$744,471	\$735,863	99%
2023	\$747,070	\$742,216	99%

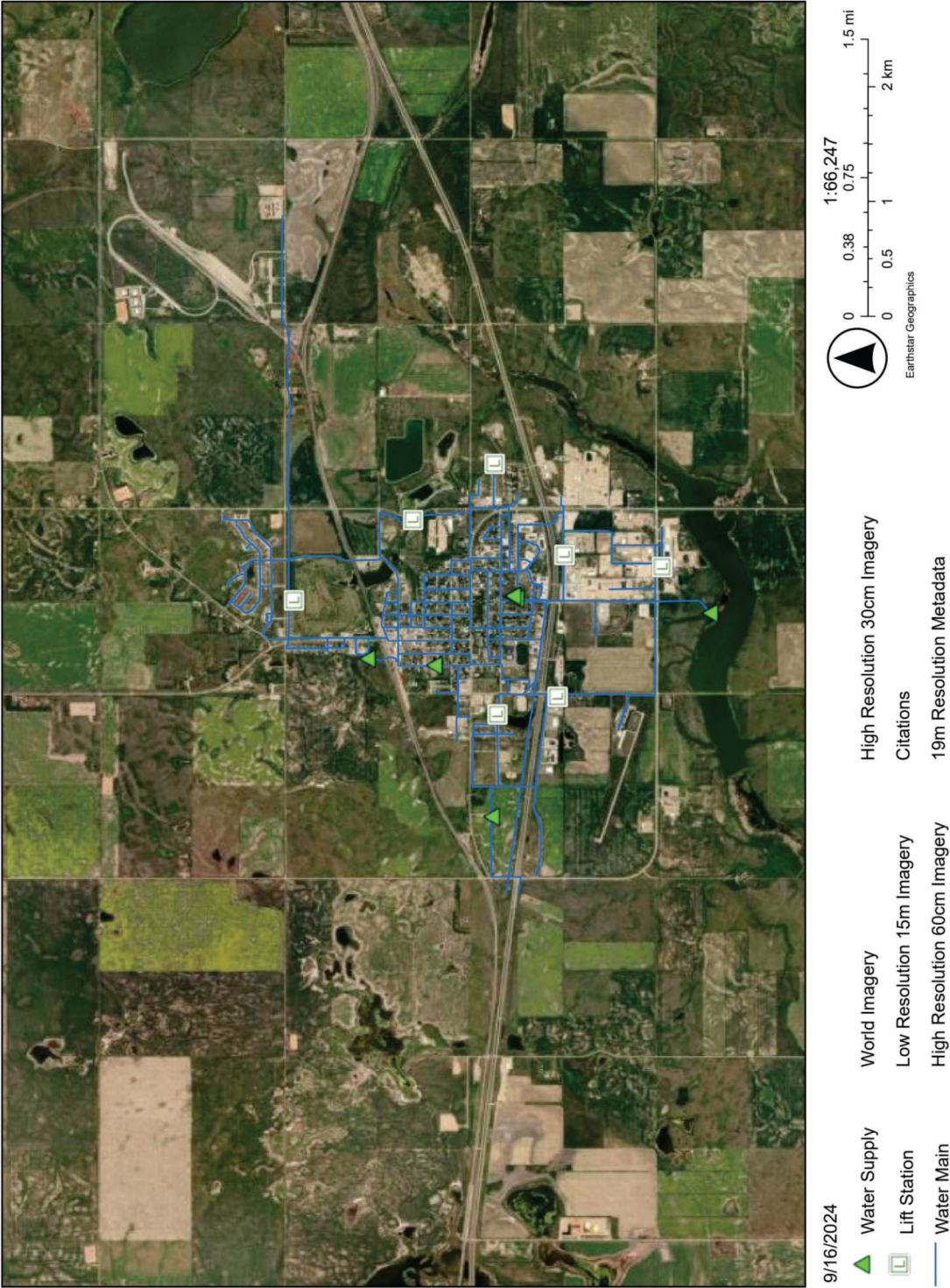
Special Assessments Certified for Collection as of 6/30/2026:

Year	Dollar Amount	Amount Collected to Date of Application	Percentage Collected
2025	\$442,184	\$281,950	64%
2024	\$430,269	\$421,625	98%
2023	\$511,326	\$499,411	98%

City of Stanley Mill Levy History:

Year	City	School	Park District	State and County	Other	Total for Each Year
2025	50.75	90.00	21.96	3.24	9.86	175.81
2024	50.75	90.00	21.16	2.21	10.10	174.22
2023	50.75	90.00	18.89	2.16	9.11	170.91
2022	50.43	90.00	16.63	12.17	9.65	178.88
2021	51.49	89.83	14.49	15.78	11.13	182.72

Stanley Public Works Map



Memorandum

To: Public Finance Authority Advisory Committee

From: DeAnn Ament, Executive Director

Date: August 4, 2026

Re: City of Stanley
Clean Water State Revolving Fund

Purpose of the Project:

Phase 3 of the street reconstruction, watermain and sanitary sewer main service replacements.

Project Cost:

CWSRF Request	\$350,000
DWSRF Request	300,000
Local Funds	1,749,807
Project Total	\$2,399,807

Population to Benefit from the Project: 2,321

Population Served by the System: 2,321

The requested term for the Clean Water State Revolving Fund (CWSRF) loans is 30 years. Accordingly, the average annual payment will be approximately \$14,648. The City will issue improvement bonds payable from special assessments. The improvement bonds will be a contingent general obligation of the City, backed by the statutory requirement that the City levy a general deficiency tax in the event that the revenues from the collection of special assessments are not sufficient to pay the debt service on the improvement bonds.

Sewer Rates:

All users pay a monthly sewer base rate of \$15.00 and \$1.50/1,000 gallons and lagoon fee of \$2.

Sewer Fund Net Operating Coverage:

	2023	2024	2025
Interest Revenue	\$1,002	\$18,738	\$12,539
Operating Revenue	294,409	289,457	289,057
Operating Expenses	147,612	233,864	403,571
Net Operating Income (Expense)	147,799	74,331	(101,975)
Depreciation	73,000	73,000	67,000
Capital Improvements Expensed	-	40,930	256,316
Adjusted Net Operating Revenue	\$220,799	\$188,261	\$221,341
Revenue Bond Payments	\$35,435	\$38,334	\$21,510 ¹
Net Operating Coverage	623%	491%	1029%

¹ The only sewer revenue bonds will be paid in full on September 1, 2026.

Outstanding Indebtedness June 30, 2026:

	Original Amount	Outstanding Amount
Improvement Bonds ²	\$5,300,299	\$2,167,467
Revenue Bonds ²	1,662,901	17,000
Total	\$6,963,200	\$2,184,467

² All payments have been made as agreed. The City has four CWSRF and four Drinking Water State Revolving Fund (DWSRF) loans with outstanding balances of \$1,234,467.

The average annual payment of all outstanding debt including this request and the DWSRF request is \$303,630 which is \$131 per resident.

Population and Employment

The City of Stanley is located in Mountrail County, 55 miles west of Minot on US Highway 2. Based on the 2020 census, the total population is 2,321; this is an increase of 863 from the 2010 census. The largest employers in the City are Mountrail County Medical Center employs 151, Stanley Public School employs 137, and Mountrail County has approximately 133 employees.

Stanley K-12 School Enrollment:

				<i>Projected</i>
2022-2023	2023-2024	2024-2025	2025-2026	2026-2027
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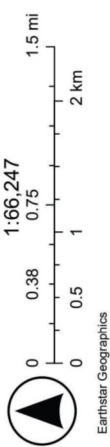
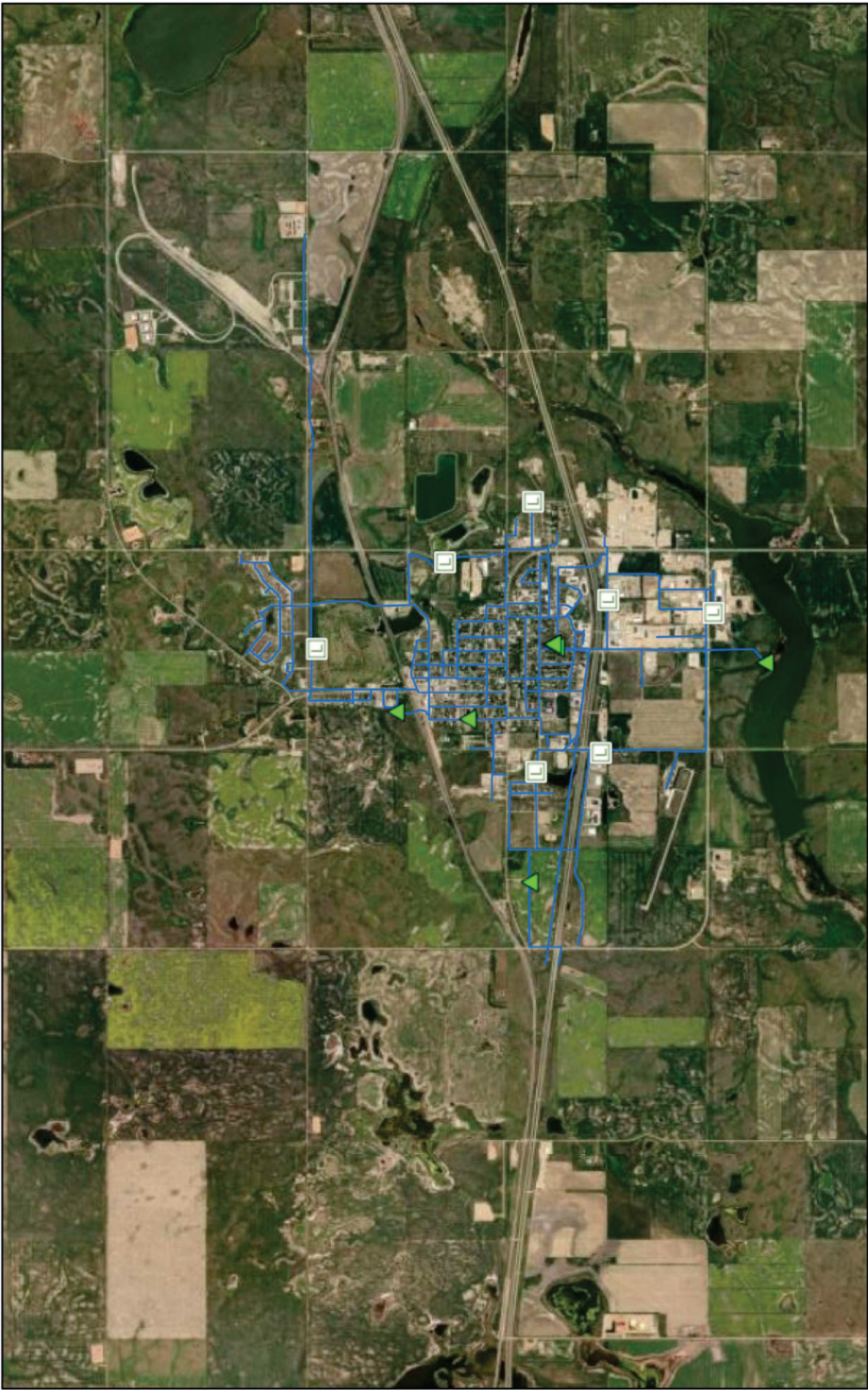
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2024	50.75	90.00	21.16	2.21	10.10	174.22
2023	50.75	90.00	18.89	2.16	9.11	170.91
2022	50.43	90.00	16.63	12.17	9.65	178.88
2021	51.49	89.83	14.49	15.78	11.13	182.72

Stanley Public Works Map



PROJECT TUNDRA

Minnkota Power Cooperative, Inc.
DCC East Project, LLC

Reliant Carbon Capture and Storage, LLC



**PROJECT
TUNDRA**

What is Project Tundra?

- World-scale carbon capture project at the coal-based Milton R. Young Station in Oliver County
- Ability to capture 5+ million metric tons of CO₂ annually
- Protects the facility from current and future EPA requirements to reduce CO₂ emissions
- Enhances and preserves 350+ energy jobs at the plant and mine, plus an additional 350 – 450 temporary employees during construction
- Project received both state and federal financial support



TIMELINE SUMMARY

- **2015–2016:** Initial concept design and early feasibility studies at the Milton R. Young Station in Center.
- **2017:** Commencement of formal CarbonSAFE geological storage and feasibility work.
- **2018–2021:** Engineering, research, and design phases backed by initial federal and state research funding.
- **2023:** U.S. DOE awarded Tundra up to \$350 million. Received \$52.8M in 2024.
 - *Initial project partners of TC Energy; Mitsubishi Heavy Industries and Kiewit Construction*
- **2023:** Minnkota & Project Tundra selected for a loan of up to \$250M by CSEA
- **2026:**
 - CSEA Commitment Letter set to expire
 - March: Industrial Commission extended loan commitment to September 31, 2026
 - Minnkota submitted a revised application in coordination with Reliant Energy in June 2026
 - Full CSEA Technical & Economic Review completed
 - Board and Technical Committee met on August 18 & forwarded recommendation to Industrial Commission

Reliant and Minnkota Team Up



Power Generation and Sequestration Site

1. Minnkota retains all control of power generation at the M.R. Young Station serving its customers first and foremost.
2. Minnkota provides its fully downstream flue gas to Reliant for CO2 capture.
3. Minnkota accepts the captured CO2 from Reliant for sequestration in the Minnkota owned CO2 Pore Space Facility.



CO2 Capture and Delivery

1. Reliant takes the downstream flue gas from M.R. Young and sends into its proprietary capture facility.
2. Reliant captures the CO2 through a cryogenic process with inherent further reduction of secondary emissions.
3. Reliant delivers the captured CO2 to Minnkota for sequestration / utilization.

Minnkota will maintain autonomy of power generation while delivering their existing flue gas to Reliant for CO2 capture.

- **Reliant offers a solution to decarbonize coal-fired power at no cost to the power company or its ratepayers.**

Project Tundra 2.0 Opportunity

All Tundra 1.0 issues addressed

1. Inflation and supply chain challenges

- Almost all the equipment and all the consumables are readily available and manufactured in the USA. Amine process no longer being considered.

2. Labor risks

- Modular design significantly reduces onsite construction needs and reduces costs

3. Construction timelines

- Modular design cuts construction time substantially. Facility should be operational in 2029.

4. Financial hurdles

- Reliant will finance, develop, build, and operate the project
- No risks or costs to Minnkota ratepayers



Reliant's History in North Dakota



- The Reliant team members have engineered and **operated projects that target emissions control at coal plants since 1995.**
- Implemented and operated mercury reduction technology at the **Milton R. Young Station from 2012-2021**

Proven Emissions Control at North Dakota Power Stations

Reliant's team successfully implemented previous emissions control programs at Milton R. Young and another North Dakota power station, operating at each station for ~10 years.

Roots in North Dakota's Coal Industry

Reliant's Executive Chairman, began his career as General Mine Foreman at the Glenharold Mine serving the Leland Olds power station, providing firsthand understanding and experience in ND's lignite coal industry.

Oil & Gas Experience in the Bakken

Reliant affiliate, NexGen Resources, maintains oil and gas lease and non-operated interests in the Bakken formation. Longstanding familiarity with North Dakota's geology, regulatory environment, and energy development landscape.

Established Relationships Across the North Dakota Energy Sector

Through decades of involvement in North Dakota's coal, oil, and power industries, Reliant's leadership team has developed strong working relationships with utilities, operators, and stakeholders across the state.



CSEA FINANCIAL CONSIDERATIONS



THE ASK: \$90MM CSEA LOAN TO MINNKOTA

Requested Loan Terms

Total Loan Commitment

\$90MM

Construction and Capex Funding
towards Geologic Storage Facilities

Interest Rate

2.0%

Fixed for the full term

Security

Senior Secured

Pari passu with senior debt

Term

12 Years

From start of operations

Sound Underwriting

- **Revenue Certainty** – Storage Fees and major maintenance accruals are contractually fixed payments
- **Fixed cashflow** – Free cashflow for debt service not tied to CO₂ tons stored (may be moved to oilfield operators)
- **Operational Independence** - Contractual certainty of cashflow for debt service as opposed to operationally dependent
- **Contractual backstop** – Contractual fixed fee payments from Reliant Tundra Capture, LLC
- **Senior secured position** – expected to rank alongside third-party senior lenders (subject to third-party lender approval)

THE ASK: \$160MM CSEA LOAN TO RELIANT

Requested Loan Terms

Total Loan Commitment

\$160MM

Construction and Capex
Funding

Interest Rate

2.0%

Fixed for the full term

Security

Senior Secured

Pari passu with senior debt

Term

12 Years

From start of operations

Sound Underwriting

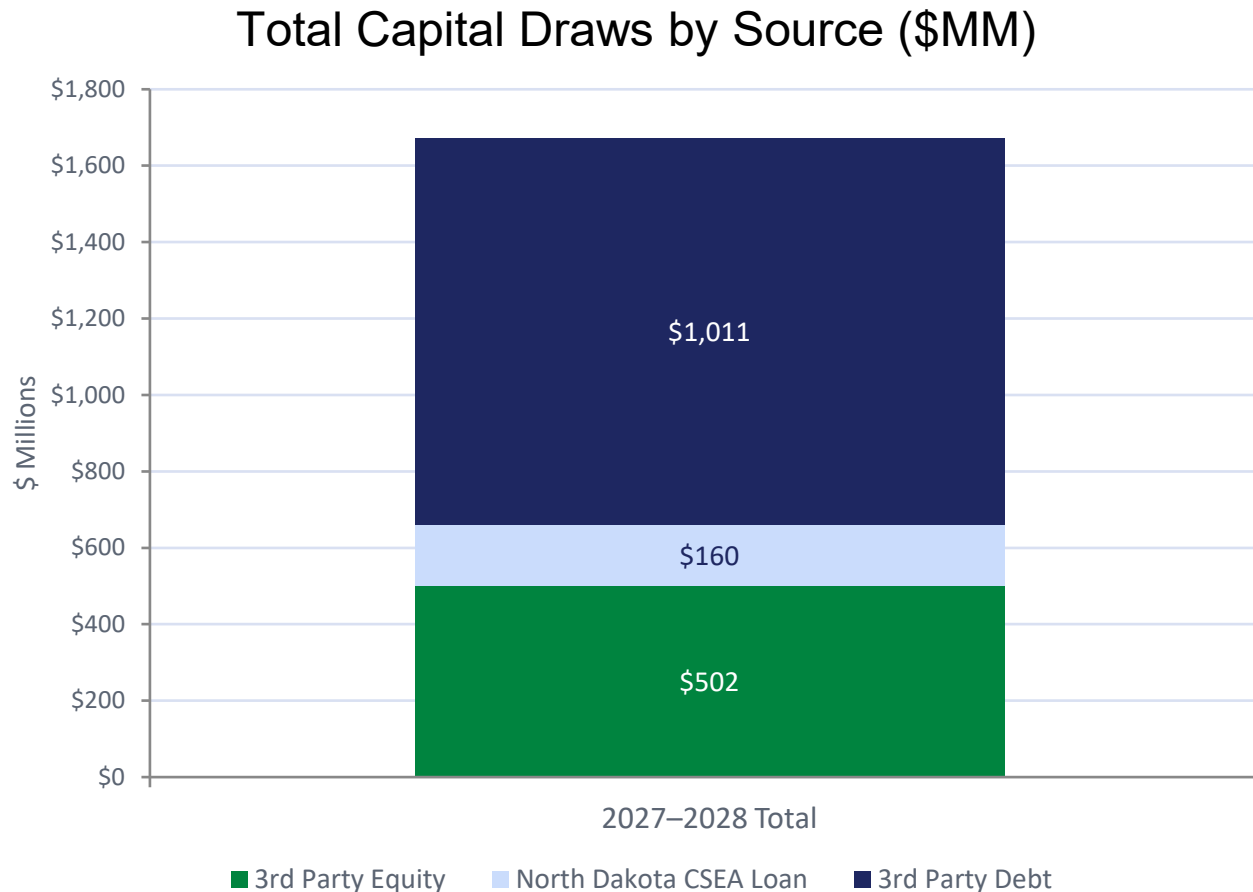
- **Strong base-case coverage** – DSCR averages supplied on confidential financial portions of the application
- **Downside tested** – coverage holds using only Minnkota's contractual minimum production (Conservative operations/downside case)
- **Conservative leverage** – 30% equity / 70% debt capital structure, with equity absorbing first losses
- **Contractual revenue backstop** – Minnkota contractually supports a minimum megawatt production level across the full 12-year term
- **Senior secured position** – expected to rank alongside third-party senior lenders (subject to third-party lender approval)
- **State capital is a minority of the stack** – \$160MM of \$1,672MM total sources; the \$350MM DOE OCED grant is excluded from the models as upside

Financing Structure: Construction-Period Capital Draws

Project Tundra – MR Young Station

Confidential and Proprietary

Sources of Construction Capital



North Dakota CSEA Loan

2.50% fixed

\$160MM

3rd Party Debt

Interest rate reflects DOE EDF rate

\$1,011MM

Total Debt

70% of Total Sources

\$1,171MM

3rd Party Equity

30% of Total Sources

\$502MM

Total Project Capitalization

\$1,672MM

QUESTIONS?



PROJECT
TUNDRA